Electricity market liberalisation in Europe Who's got the power?

Lise, W.; Linderhof, V.G.M.

2004

Electricity market liberalisation in Europe – Who's got the power?

Wietze Lise & Vincent Linderhof

R-04/03

October 2004

This report was commissioned by the European Commission.

It was internally reviewed by Onno Kuik.

IVM

Institute for Environmental Studies
Vrije Universiteit
De Boelelaan 1087
1081 HV Amsterdam
The Netherlands

Tel. ++31-20-4449 555
Fax. ++31-20-4449 553
E-mail: info@ivm.falw.vu.nl

Contents

Abstract iii

1. Introduction 1

2. Data characterising the European electricity market 5
   2.1 Electricity producers 5
   2.2 Demand and supply 7
   2.3 Trade and transmission losses 7
   2.4 Production technologies 8
   2.5 Emission factors 10
   2.6 Cross-ownership 11

3. The EMELIE model 13
   3.1 Identities 14
   3.2 Constraints 15
   3.3 Profit maximisation in the electricity market 16
   3.4 Different types of firm behaviour 17
   3.5 Cross-ownership 18

4. Scenarios of electricity producer behaviour 21

5. Results 23
   5.1 Load periods 26
   5.2 Price decomposition 27
   5.3 Individual firms 29
   5.4 Environment 30

6. Sensitivity analysis 33
   6.1 Transmission losses (LAMBDA) 33
   6.2 Alternative division of peak and base load periods (PEAKBASE) 34
   6.3 Uniform prices (UNIFORM) 37
   6.4 Price elasticities of demand 38
      6.4.1 Similar price elasticities for peak and base load demand (ELASEQ) 39
      6.4.2 Varying the level of elasticities of demand (ELASTIC) 40
   6.5 Transmission capacity (TRANSM) 41
   6.6 Environmental constraints (ENVIRON) 42
   6.7 Comparison 43

7. Conclusions 45

References 47

Abstract

The European electricity market is in the middle of a transformation from monopolistic state-owned production and distribution to privatised markets, with various competing firms. The speed of privatisation differs widely across Europe from full trade of electricity at the wholesale market in Scandinavian countries, to partial trade on the wholesale market in The Netherlands and Germany, and no trade on the wholesale market in France and Belgium. Hence, the market and its rules are no longer fixed, and the electricity market is in the middle of a dynamic and complex process of change.

This report discusses whether the liberalisation process can result in more efficient electricity production in Europe. In addition, the environmental impacts of the liberalisation process are studied. Efficiency of electricity production is analysed with a static computational game theoretic model, which compares strategic options of and interactions among energy suppliers. This model is calibrated to the European electricity market in eight countries, namely Belgium, Denmark, Finland, France, Germany, The Netherlands, Norway, and Sweden.

In a liberalised market, large firms are most likely to behave strategically and exercise market power in order to maximise profits. As a result, wholesale prices might increase, partially or fully off-setting the purpose of liberalisation, namely to decrease wholesale prices. Also, a potential market leader may emerge, who by anticipating on the reaction of followers, could acquire higher profits by increasing production and market share. Finally, firms can also acquire passive ownership in other firms. Passive cross-border ownership can increase a firm's market power and profits, resulting in even higher wholesale prices.

The environmental impacts of different scenarios of producer behaviour are ambiguous. Under full competition, greenhouse gas emissions decline compared to the initial situation, while acidification and smog formation increase. In the case where large firms act strategically, the levels of emission decrease due to higher electricity prices and lower levels of electricity demand. In the case with a potential first-moving market leader, the levels of emission increase substantially. This result, however, depends on the technology mix of the electricity capacity of the market leader.

1. Introduction

Following EU Electricity Directive 96/92/EC, liberalisation of the European electricity market is going to be realised by all EU countries by 2007 (Schils, 2003). The European electricity market is in the middle of a transformation from monopolistic state-owned production and distribution to privatised markets, with various competing firms. The speed of privatisation differs widely across Europe from full trade of electricity at the wholesale market in Scandinavian countries, to partial trade on the wholesale market in the Netherlands and Germany, and no trade on the wholesale market in France and Belgium. Hence, the market and its rules are no longer fixed, and the electricity market is in the middle of a dynamic and complex process of changes.

In order to get insight into the possible economic and environmental impacts of the liberalisation process of the electricity market, the EU has commissioned the EMELIE[1] (Electricity MarkEt Liberalization In Europe) project. Within the EMELIE project, scientific researchers and representatives of electricity producers collaborated. The participants of the EMELIE project originated mainly from northwestern Europe. The EMELIE project focussed attention on the electricity markets of 8 countries, namely Belgium, Denmark, Finland, France, Germany, The Netherlands, Norway and Sweden, which we refer to as EU8.

Figure 1.1 shows the shares in electricity capacity and demand for electricity of the EU8 countries in the year 2000. In 2000, the total electricity capacity in these eight countries amounted to 259 GW, while the total demand for electricity amounted to 1,423 TWh. France has the largest share of electricity capacity with 35%, and Germany has the largest share of demand for electricity with 34%. Denmark is the smallest country with a share of 4% of the electricity capacity and with a share of 2% of total demand.

The process of liberalisation may have serious consequences for the market structure of the European electricity market. From the economic theory of industrial organisation (Tirole, 1988), we know that there is a range of possible market structures, which could become applicable to the liberalised electricity market. There are two extreme possible market structures, namely monopoly and perfect competition. In the monopoly case, there is one large and dominant firm (monopolist), as is the case of EdF in France. Due to its position, EdF could affect the market price of electricity in France in a liberalised market. In perfect competition, there are a substantial number of electricity producers with small market shares. None of the firms can execute any dominancy in the electricity market, and therefore, they cannot affect market prices. Between these two extreme market structures, there is a wide range of other possibilities, which are the so-called oligopolies. In the case of oligopolies, there are a limited number of medium-sized or large firms, and these firms dominate the supply of electricity.

---

[1] Contract number NNE5-2001-00519. For more information on this project, one can refer to the website: http://www.uni-oldenburg.de/speed/english/projects/emelie.htm.

Due to the size of these firms, they can affect market prices. In Germany, for instance, the initial number of 30 small companies has reduced to four large firms over a time span of a few years due to the process of liberalisation. In order to reduce market power on the national markets, governments introduce maximum allowable market shares. Although these limitations apply to domestic markets, there is no restriction on acquiring market shares in adjoining markets.

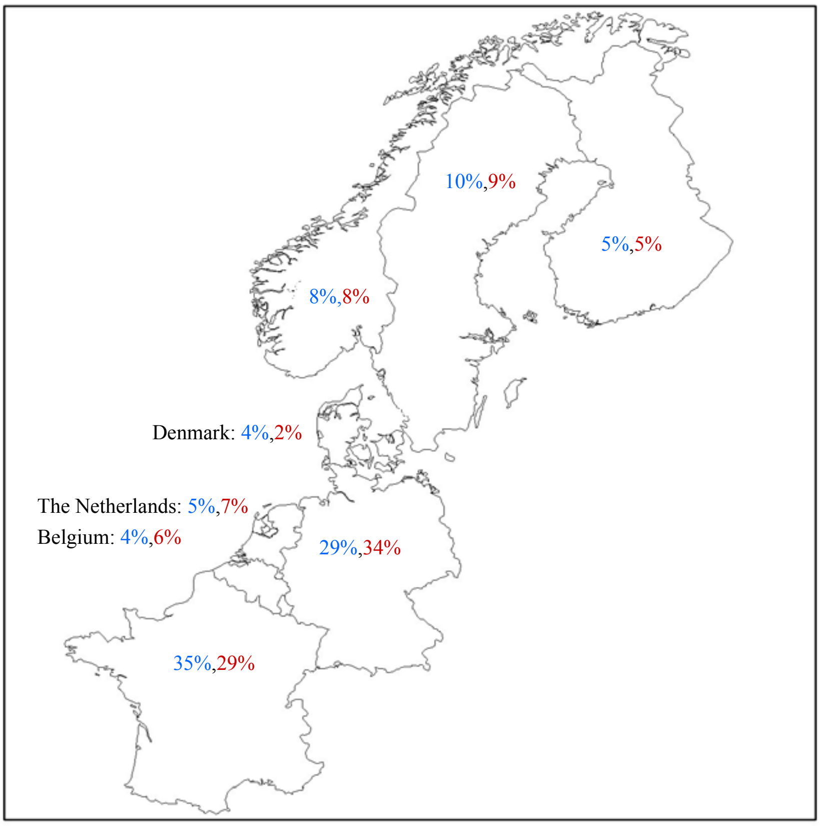

Figure 1.1 The electricity market in eight European countries.

Note: The first (blue) percentages represent shares in electricity capacity and the second (red) percentages represent shares in demand for electricity.

If large firms all act in a similar way, by making production decisions simultaneously, the electricity market is said to end up in a so-called Cournot-Nash equilibrium. Alternatively, one could imagine that one firm attempts to increase its market share and profits by supplying electricity below the price of the Cournot-Nash equilibrium. This company subsequently increases its supply and market share. In fact, this firm strives for market leadership. In this setting, the electricity market is said to end up in a so-called Stackelberg equilibrium.

Currently, there is still little known about the environmental consequences of the liberalisation process. The goal of liberalising the electricity market is to achieve more efficient production due to more competition, and consequently lower electricity prices. This goal includes two opposite effects with respect to the environment. On the one hand, more efficient production can reduce the burden on the environment, and on the other hand, lower market prices imply higher demand for electricity, which is likely to be accompanied with an increase of the burden on the environment. The environment is not necessarily worse-off in the case of high electricity prices. Another environmental issue is that since profit maximisation becomes increasingly important for private electricity producers, they are less likely to investment in renewable energy, while high efficiency production technologies might become less attractive.[2] Moreover, in the near future, new developments, such as the implementation of the CO_2 emission trading system in 2005, might have major impacts on the electricity market as well.

Within this EMELIE project, we have developed a game theoretical model to gain insight in this complex process of economic and environmental changes. With this model, we can study the consequences of various types of market behaviour of electricity producers on different kinds of aspects. The main research question is: What will happen to the wholesale price of electricity, the demand for electricity, the profits of firms, and finally the different kind of emissions under different scenarios of producer behaviour?

The EMELIE model as described in this report is an extended version of the original computational game theoretic model applied to the German electricity market as in Kemfert (1999), Kemfert and Tol (2000), and Lise *et al*. (2003). The original model is extended in four ways. First of all, the model considers 8 European countries instead of regions within Germany, where trade of electricity is possible among countries. Secondly, environmental impacts are calculated by adding emission factors to the generation technologies used for production in the EMELIE model. Thirdly, the present model distinguishes two load periods, peak load (hours with particularly high demands for electricity) and base load (hours with more average demands for electricity). For both load periods, we consider separate electricity markets. Finally, within the EMELIE model we can take cross-ownership relationships into account. The EMELIE model combines many different aspects of the electricity market, which makes it a unique model in comparison with other electricity market models (i.e. Bigano and Proost 2003; Amundsen and Bergman, 2002; Pineau and Murto, 2003).

The present EMELIE model is a static year-based model and not an hour-based model, because we are interested in economic and environmental consequences of market producer behaviour at the aggregate level. It is not our primary interest to address the economic consequences of the daily electricity trade at the electricity exchanges. Furthermore, we make some simplifying assumptions on some relevant issues. For instance, we do not consider a separate market for green electricity (renewable energy). Also, in the case of combined heat and power (CHP) generation, we do not take into account the heat market. Finally, we do not consider substitution opportunities between natural gas and electricity.

---

[2] The EU directive, 2001/77/EC, indicates to obtain a share in the consumption of renewable energy of 22.1% by 2010 for the electricity sector. Report available from: http://europa.eu.int/eur-lex/pri/en/oj/dat/2001/l_283/l_28320011027en00330040.pdf.

The outline of this report is as follows. Chapter 2 presents and discusses data on the electricity market in the EU8 countries for the base year 2000. A full and extensive description of the EMELIE model with trade and environmental constraints is given in Chapter 3. In Chapter 4 we discuss five different scenarios of producer behaviour. Chapter 5 presents the results of these five scenarios; we consider this as the base run of the EMELIE model. In Chapter 6 we undertake a series of sensitivity analyses in order to verify the model parameters as used in the EMELIE model. The final chapter concludes.

2. Data characterising the European electricity market

The EMELIE project has focused attention on the collection of data in eight EU countries for the year 2000. The data include information on individual electricity producers, demand and supply of electricity on the national electricity markets, the production technologies, the interconnection capacity between countries, transportation losses per country, emission factors of electricity production per country, and cross-ownership shares between firms in the EU8 (Kemfert *et al*. 2004).

2.1 Electricity producers

In the electricity market of the EU8 we distinguish in total 34 different electricity producers or firms. Table 2.1 presents the list of companies and the location of the firms. In Belgium, Denmark and France, there are only two firms distinguished. In fact, these countries have one major electricity producer in terms of electricity capacity and several firms with a limited electricity capacity. These small firms are included in the fringe of a country. In Norway and Sweden, there are 7 firms distinguished including the fringe.

From Table 2.1 we can also see that three companies are present in two countries, such as Vattenfall, EON, Electrabel and Fortum. For instance, Vattenfall originates from Sweden and it has a subsidiary in Germany. EON is from Germany and Electrabel is a Belgian company and both companies have a subsidiary in the Netherlands. Fortum (Finland) is the parent company of Fortum Kraft (Sweden). Next to these four subsidiaries, there are more cross-ownership relationships within the EU8, which we will elaborate on in Section 2.6.

Furthermore, Table 2.1 shows the available production capacity per firm as well as the two main production technologies based on the available capacity. The three largest firms in the EU8 market are EdF (France), RWE (Germany) and E.ON (Germany). The electricity capacity of EdF is almost 75 GW, which is approximately 29% of the total electricity capacity in the EU8. The sizes of RWE and E.ON are less then one third of the size of EdF, as the electricity capacities of RWE and E.ON are 24.8 GW (9.6%) and 21.5GW (8.3%) respectively. For all three firms nuclear power is the main or second technology. In particular, 80% of the electricity capacity of EdF is nuclear power. RWE and E.ON use lignite for electricity production. In Norway and Sweden, hydropower is often the main technology.

Table 2.1 Overview of firms in the EU8: location, available production capacity and main production technologies.

Firms	Country[3]	Acronym of firm	Available production capacity (in GW)	Main technology	Second technology
Fringe	Belgium	FrinBEL	1.226	Nuclear	Gas
Electrabel*	Belgium	ElectBEL	11.231	Nuclear	Gas
Fringe	Denmark	FrinDEN	1.926	CHP gas	Wind
ElsamE2	Denmark	ElsamE2	7.085	Coal	CHP gas
Fringe	Finland	FrinFIN	5.959	CHP others	CHP gas
Fortum*	Finland	Fortum	4.157	Nuclear	Coal
PVO	Finland	PVO	2.646	Nuclear	Coal
Fringe	France	FrinFRA	16.131	CHP others	Oil
EDF	France	EDF	74.795	Nuclear	Hydro
Fringe	Germany	FrinGER	10.908	–	–
EnBW	Germany	EnBW	7.970	Coal	Gas
E.ON*	Germany	EONGER	21.459	Nuclear	Lignite
Vattenfall	Germany	VattenGER	14.371	Coal	Gas
RWE	Germany	RWE	24.809	Lignite	Nuclear
Fringe	The Netherlands	FrinNLD	2.856	CHP gas	Gas
Electrabel	The Netherlands	ElectNLD	3.980	Gas	Coal
NUON	The Netherlands	NUON	3.225	Gas	Oil
E.ON	The Netherlands	EONNLD	1.515	Coal	Gas
Essent	The Netherlands	Essent	3.336	Gas	Coal
Fringe	Norway	FrinNOR	0.582	Hydro	Wind
Statkraft	Norway	Statkraft	5.846	Hydro	–
OsloEn	Norway	OsloEn	4.903	Hydro	–
NorskHy	Norway	NorskHy	1.247	Hydro	–
Agder	Norway	Agder	1.020	Hydro	Wind
BKK	Norway	BKK	0.971	Hydro	CHP others
Lyse	Norway	Lyse	0.910	Hydro	–
Fringe	Sweden	FrinSWE	0.877	Oil	CHP others
Vattenfall*	Sweden	VattenSWE	4.403	Nuclear	Hydro
Sydkraft	Sweden	Sydkraft	9.702	Nuclear	Hydro
Birka	Sweden	Birka	4.522	Hydro	Nuclear
Fortum Kraft	Sweden	FortumK	3.069	Hydro	Nuclear
Skellefte	Sweden	Skellefte	0.988	Hydro	Nuclear
Graninge	Sweden	Graninge	0.413	Hydro	–

* Origin of firms, which are present in more than one country.

[3] To make the upcoming tables more readable, we use the following acronyms to refer to the 8 countries in the remainder of this report: Belgium (BEL), Denmark (DEN), Finland (FIN), France (FRA), Germany (GER), the Netherlands (NLD), Norway (NOR), and Sweden (SWE).

2.2 Demand and supply

The number of firms is not evenly distributed over the individual countries. Table 2.2. shows this. As explained before, there is a fictive firm in all countries, namely the price-taking competitive fringe. These national fringes are actually a collection of individual and decentralised electricity production units, which often have a limited amount of electricity capacity. In the case of the Netherlands, however, the fringe owns approximately 30% of total electricity capacity. In Belgium and France, where the liberalisation process is being introduced the latest, there is only one electricity producer next to the fringe, which can serve the whole local market and beyond.

Table 2.2 Regional elasticities, electricity losses due to transport, reference price and reference demand in 2000.

	BEL	DEN	FIN	FRA	GER	NLD	NOR	SWE
Number of firms	2	3	3	2	5	5	7	7
Prices (€/MWh)	39.65	17.41	14.88	20.81	18.19	39.65	12.25	14.26
Demand (GW)	9.04	3.75	8.72	46.88	54.45	11.48	12.66	15.46

Source: Kemfert *et al* (2004).

Besides the 34 firms in the EU8 market, Table 2.2 also shows the reference demand and reference price for the eight national electricity markets in 2000. The electricity prices range form €12.25 in Norway to €39.65 in Belgium and the Netherlands. Germany has the largest demand for electricity, and Denmark the lowest.

2.3 Trade and transmission losses

Firms in the EMELIE model are assigned to a specific country. The EMELIE model includes the opportunity to trade electricity between countries. However there are two restrictions. Firstly, imports and exports to countries outside the EU8 are ignored in the model. Secondly, trade in the model is only allowed between neighbouring countries. The interregional transport capacity of the electricity network is as presented in Table 2.3. Note that the table is asymmetric. The interconnection capacity from France to Belgium (2,850 MW), for instance, is larger than the capacity from Belgium to France (2,500 MW). The transmission capacity within a country is considered to be unrestricted. Interconnections with non-EU8 countries are not taken into account.

Electricity transmission through the electricity grid is accompanied by loss of electricity. These losses occur when electricity is transported within a country as well as between countries. The transmission losses within countries are at the diagonal of Table 2.4 and they differ across countries. The average transmission losses range from 3.9% of total amount of electricity produced in the Netherlands to 8.9% in Norway. We assume that the percentage of transmission losses of exported electricity is just the sum of the two domestic percentages of transmission losses. If a Dutch firm exports 1 TWh of electricity to Germany, it faces 8.4% (=3.9%+ 4.7%) transmission losses. A German firm would face the same 8.4% transmission losses if it exports electricity to the Netherlands.

Table 2.3 Transmission capacities between EU8 countries in MW's.

	BEL	DEN	FIN	FRA	GER	NLD	NOR	SWE	Total
Belgium				2,500	0	1,400			3,900
Denmark					1,750		950	1,900	4,600
Finland							70	1,450	1,520
France	2,850				1,150				4,000
Germany	0	1,350		1,750		3,300		550	6,950
Netherlands	1,400				3,300				4,700
Norway		950	70					3,035	4,055
Sweden		1,840	2,050		550		3,035		7,475
Total	4,250	4,140	2,120	4,250	6,750	4,700	4,055	6,935	

Note: An empty cell means that the countries are not neighbouring countries.
Source: Kemfert *et al* (2004).

Table 2.4 Transmission losses (percentage of produced electricity) within and between EU8 countries in MW's.

	BEL	DEN	FIN	FRA	GER	NLD	NOR	SWE
Belgium	4.5%			11.3%		8.4%		
Denmark		6.5%			11.2%		15.4%	14.7%
Finland			3.5%				12.4%	11.7%
France	11.3%			6.8%	11.5%			
Germany		11.2%		11.5%	4.7%	8.4%		12.9%
The Netherlands	8.4%				8.4%	3.9%		
Norway		15.4%	12.4%				8.9%	17.1%
Sweden		14.7%	11.7%		12.9%		17.1%	8.2%

Note: An empty cell means that the electricity grids of neighbouring countries are not connected, as is the case of Belgium and Germany.
Source: Kemfert *et al* (2004).

2.4 Production technologies

For the EU8 we distinguish 12 different production technologies, namely eight fossil fuel based technologies, nuclear power, power from biomass, hydropower, and wind power. For coal, gas and oil, we distinguish between technologies which are either solely used for electricity production or for the combined cogeneration of heat and power. Table 2.5 shows that individual countries have their own specialisation in technologies of electricity production. Norway is specialised in hydropower while France relies on nuclear power. The installed capacity presented in Table 2.5 is corrected for the availability of the particular technology. The availability is reflected in an availability percentage, which is defined as the number of hours per year that a technology can be used for electricity production divided by the total number of hours per year. In the case of nuclear power or fire-based technologies, the availability percentage is 85%, while wind power is available for 23%. For hydropower, the availability percentage differs across countries. Among the largest producers of hydropower, the availability percentage is more than 50% in Norway and Sweden, while it is about 32% in France.

Table 2.5 Installed capacity (in GW) and assumed availability (in %) per technology in the EU8 countries.

	BEL	DEN	FIN	FRA	GER	NLD	NOR	SWE	Availability
Nuclear	5.71		2.64	63.18	21.37	0.45		9.46	85.6%
Coal	2.95	5.10	2.29	12.69	17.86	4.05			85.6%
Lignite					18.97				85.6%
Gas	3.50	0.04	0.90	1.89	13.82	7.17			85.6%
Oil	1.20	0.79	1.24	12.23	8.11	0.99		4.64	85.6%
CHP-gas	0.58	2.58	1.80		0.99	4.66		0.13	85.6%
CHP-coal		1.13	1.47		6.96			0.56	85.6%
CHP-oil	0.10		0.16		0.30			0.65	85.6%
CHP-bio	0.29	0.23	1.04			0.64		0.46	85.6%
CHP-others			1.44	6.64			0.20	1.00	85.6%
Hydro	1.40	0.01	2.88	25.60	11.61	0.04	27.46	16.33	
Wind	0.01	2.42	0.04	0.08	0.36	0.44	0.01	0.25	22.8%
Total	15.74	12.30	15.89	122.31	100.33	18.44	27.67	33.48	
Availability Hydro	13.7%	34.2%	57.3%	31.9%	32.6%	40.0%	56.8%	54.4%	

Note: The capacity is corrected for availability. Availability is the share of regular number of hours that the technology is available for production. Except for hydropower, the availability is the same for all countries. Empty cells mean that the technology is absent in the country.

Source: Kemfert *et al* (2004).

Table 2.6 presents the variable costs for producing electricity. Variable costs are calculated as gross production costs, consisting of fuel cost including taxes and costs for operation and management including taxes. We assume that the variable production costs differ across regions and technologies, but not across producers. Thus, if two firms located in a country explore the same production technology, they face the same variable costs. If two firms located in different countries explore the same production technology, the variable production costs might differ, as in the case of coal technology for instance. Empty cells in Table 2.6 reflect the absence of particular technologies in a country. Denmark, for example, has no nuclear power, and Norway has no gas-fired technologies.

Table 2.6 Variable costs (€/MWh) per technology in the EU8 countries.

	BEL	DEN	FIN	FRA	GER	NLD	NOR	SWE
Nuclear	6.14		6.14	6.14	6.14	6.14		7.50
Coal	16.94	13.83	13.97	15.19	14.42	16.83		
Lignite					14.42			
Gas	24.22	23.81	20.28	23.83	29.04	23.25		
Oil	36.42	35.21	35.21	38.84	38.70	41.21		39.83
CHP-gas	13.29	13.08	11.21		15.85	12.78		13.52
CHP-coal		7.57	7.63		7.84			11.73
CHP-oil	19.58	19.58	19.58		21.43			21.58
CHP-bio	19.94	19.94	19.94			19.94		19.94
CHP-others			14.59	16.69			16.69	16.69
Hydro	0.00	0.00	0.00	5.84	0.00	0.00	0.00	1.18
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Note: An empty cell means that the technology is not used in the country.

Source: Kemfert *et al* (2004).

2.5 Emission factors

For the 12 technologies, we have used emission factors for six gases, namely CO_2, SO_2, NO_x, CH_4, N_2O and PM10 (Heinzow, 2004, personal communication). From these gases, we have derived three environmental themes, namely greenhouse gas emissions, acidification, and smog formation (due to emissions of fine particles). For greenhouse gases we use CO_2 emission equivalents, where 0.310 kg N_2O = 0.021 kg CH_4 = 1 kg CO_2. One unit of acidification is equivalent to 1/32 SO_2 = 1/46 NO_2. The emission factor of smog is simply the amount of PM10 emitted. The emission factors differ across technologies and countries. Table 2.7, Table 2.8, and Table 2.9 present the emission factors for greenhouse gas emission, acidification and smog formation respectively.

Table 2.7 Greenhouse gas emission factors (kg CO_2 equivalents/MWh) per technology in the EU8 countries.

	BEL	DEN	FIN	FRA	GER	NLD	NOR	SWE
Nuclear	0		0	0	0	0		0
Coal	920.0	972.2	915.9	915.9	970.0	915.9		
Lignite					1219.7			
Gas	388.0	327.2	348.9	401.9	348.9	411.0		
Oil	877.3	692.6	877.3	756.8	877.3	877.3		877.3
CHP-gas	330.6	673.9	528.3		327.1	327.1		327.1
CHP-coal		948.9	776.1		33.1			733.1
CHP-oil	503.4		503.4		503.4			503.4
CHP-bio	0.0	81.9	2.1			0.0		0.0
CHP-others			1296.1	401.6			403.4	403.4
Hydro	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0

Note: An empty cell means that the technology is not used in the country.
Source: Heinzow (2004, personal communication) and own calculations.

Table 2.8 Emission factors for acidifying emissions (g acid equivalents/MWh) per technology in the EU8 countries.

	BEL	DEN	FIN	FRA	GER	NLD	NOR	SWE
Nuclear	0		0	0	0	0		0
Coal	31.549	20.699	23.310	31.549	23.307	28.365		
Lignite					33.896			
Gas	5.901	2.174	4.522	15.435	4.522	6.783		
Oil	21.821	2.486	21.821	25.610	21.821	21.821		21.821
CHP-gas	2.174	19.833	6.848		2.174	2.174		2.174
CHP-coal		20.217	32.459		2.649			2.649
CHP-oil	2.486		2.486		2.486			2.486
CHP-bio	7.160	31.692	46.726			7.160		12.288
CHP-others			83.071	15.435			3.736	3.736
Hydro	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0

Note: An empty cell means that the technology is not used in the country.
Source: Heinzow (2004, personal communication) and own calculations.

Table 2.9 Emission factors for smog formation (g fine particles /MWh) per technology in the EU8 countries.

	BEL	DEN	FIN	FRA	GER	NLD	NOR	SWE
Nuclear	0		0	0	0	0		0
Coal	80.0	57.0	172.9	170.0	66.0	17.0		
Lignite					96.0			
Gas	0.0	0.0	0.0	0.0	0.0	0.0		
Oil	21.0	1.0	3.0	130.0	2.0	2.0		21.0
CHP-gas	0.0	0.0	0.0		0.0	0.0		0.0
CHP-coal		57.0	150.0		10.0			10.0
CHP-oil	1.0		2.0		2.0			2.0
CHP-bio	30.0	0.0	21.0			30.0		233.0
CHP-others			195.0	0.0			1.0	1.0
Hydro	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0

Note: An empty cell means that the technology is not used in the country.
Source: Heinzow (2004, personal communication).

With the emission factors, we can include environmental constraints in the model which reflects a certain degree of environmental policy. However, we have to be careful with this interpretation, because the electricity sector is not the only emitting sector in the economy. Since the EMELIE model focuses attention on the electricity market, objectives of environmental policy with respect to emissions have to be translated into specific objectives for the electricity sector. The emission factors are specific for the technologies of electricity production per country.

Since we focus attention on three environmental themes, nuclear power, hydropower and wind power do not have any environmental impact. For all three technologies, the emission factors are zero. The dirtiest technologies are the technologies which combust coal, lignite or oil. In some cases there is asymmetry in emission factors. For instance, the technology CHP-others in Finland has high emission factors for acidification and smog formation, while it has a very low emission factor for green house gas emissions.

2.6 Cross-ownership

Table 2.10 presents the cross-ownership shares of the companies in the EU8 in 2000.[4] Since we only consider the EU8 electricity market, we ignore any cross-ownership with companies residing in non-EU8 countries. Four subsidiaries are fully owned by parent companies: Electrabel Netherlands, EON Netherlands, Vattenfall Germany, Fortum Kraft (Sweden). For convenience, Table 2.10 presents a condensed matrix of cross-ownership, and companies not mentioned are independent companies with respect to other companies in the EU8. Since we distinguish 34 firms, the total matrix of cross-ownership is a square matrix with order 34.

[4] As we calibrate the EMELIE model on the data of the year 2000, we present the cross-ownership shares of this year. However, the market of electricity producers is highly active due to the liberalisation process, and actual shares of cross-ownership may differ from those in Table 2.10.

Table 2.10 Condensed cross-ownership shares of firms in the EU8.

		Subsidiaries or partly owned companies											
Parent		E2 Energi	PVO	EON	Vattenfall	Electrabel	EON	Oslo Energi	BKK	Sydkraft	Birka Energi	Fortum Kraft	Graninge
companies		DEN	FIN	GER	GER	NLD	NLD	NOR	NOR	SWE	SWE	SWE	SWE
Electrabel	BEL					100%							
Fortum	FIN										50%	100%	
EdF	FRA												36%
E.ON	GER			-			100%			21%			13%
Statkraft	NOR							20%	26%	35%			
Vattenfall	SWE	4%			100%			39%					
Sydkraft	SWE			1%						-			23%
Graninge	SWE		1%										-
Total		4%	1%	1%	100%	100%	100%	59%	26%	56%	50%	100%	72%

Source: Van der Woerd and Lise (2004).

Table 2.10 also shows that in the EU8, there are four full subsidiaries, Electrabel Belgium owns Electrabel in the Netherlands, Fortum Kraft in Sweden is owned by Fortum (Finland), E.On (Germany) owns E.On Benelux in the Netherlands, and Vattenfall in Germany is fully owned by Vattenfall in Sweden. In all four cases, the location of the parent company differs from the location of the subsidiary.

Most cross-ownership relations are trans-boundary. Only Statkraft from Norway has a share in BKK and Oslo Energi are both located in Norway. Another example is Sydkraft (Sweden) that has a share in Graningen. For a more detailed discussion on the cross-ownership issue in the European electricity market, we refer to Van der Woerd and Lise (2004).

3. The EMELIE model

The EMELIE model is a game theoretic model of the liberalised electricity market. With the EMELIE model we can study economic and environmental consequences of different kinds of producer behaviour. The model is based on profit maximization of the electricity producers including features such as capacity constraints of production (per technology) and interconnection in the case of trade between countries, and emission restrictions due to environmental policy. Besides, the model distinguishes two load periods, namely peak hours (hours during the day) and base hours (hours at night). All in all, the main feature of the model is that it allows one to assess different kinds of producer behaviour in the case of market power in a liberalised electricity market.

Table 3.1 presents the sets and indices, parameters and variables of the EMELIE model.

Table 3.1 Indices, parameters and variables in the EMELIE model.

Sets and indices	Description	Units
F	Firms	
I	Technologies $i \in I$	
R	Regions/countries $r \in R$	
L	Load period $l \in L$ = {base, peak}	
K	Emission type $k \in K$ = {ghg, acid, pm10}	
F_{r^*}	Firms in country r^*	
Parameters:		
$c^{v}_{i,r}$	Variable production costs	€ per MWh
$d^{0}_{r,l}$	Reference demand for electricity	TWh
$p^{0}_{r,l}$	Reference price for electricity	€ per MWh
$\varepsilon_{r,l}$	Price elasticity of electricity demand	
λ_{r,r^*}	Loss of electricity due to transport	%
η_{r,r^*}	Maximum trade possibility	MW
$\sigma_{i,r,k}$	Emission factor	g per MWh
$q^{max}_{i,f}$	Maximum production capacity	GW
E_k	Emission permits	g
h_l	Number of operating hours	
$\xi_{f,l}$	Reduction in 'market power' mark-up	
Variables:		
Π_f	Profit of firm f	€
$p_{r,l}$	Market price for electricity	€ per MWh
$c^{m}_{i,f,r,l}$	Marginal costs of electricity production	TWh
$\mu_{i,f,l}$	Shadow price of capacity constraint	€ per MWh
$\tau_{r,r^*,l}$	Shadow price of trade constraint	€ per MWh
κ_k	Shadow price of emission constraint	€ per MWh
$\vartheta_{f\,r,l}$	Supply share of the market per firm	%
$s_{f\,r,l}$	Supply of electricity per firm	TWh
$S_{r,l}$	Total supply of electricity per region	TWh
$q_{i,f,r,l}$	Production of electricity	TWh
$x_{r,r^*,l}$	Net trade between region r and region r^*	TWh
Em_k	Current level of emissions	g

Note: The model is written as a Mixed Complementary Problem (MCP). The parameters of the model are exogenous in the model, while the model determines the value of the variables.

In a liberalised electricity market, firms maximise their profits by producing electricity with different kinds of technologies *i*, and by selling this electricity in the countries of a European market. In particular, producers distinguish between two separate markets based on the peak in electricity demand, namely peak hours and base hours. The profits are the difference between the revenues from selling electricity and the costs of production. The prices of electricity differ across countries and load periods and in addition these prices might depend on the level of total electricity demand in a country during a particular load period. This dependency reflects particular strategic behaviour of the electricity producers. The firms base their decision on the amount of electricity produced given the load period, technology and market ($q_{i,f,r,l}$). The profit function for firm *f* is:

$$\Pi_f = \sum_{l\in L} h_l \sum_{r\in R}\left(p_{r,l}\left(S_{r,l}\right)s_{f,r,l}\right) - \sum_{l\in L} h_l \sum_{r\in R}\left(\sum_{i\in I} c^{\mathrm{v}}_{i,r*} q_{i,f,r,l}\right) \tag{3.1}$$

The first term reflects the total amount of revenues from supplying electricity, while the second term summarizes the total amount of costs of electricity production. Note that the revenues depend on the amount of electricity supplied, and the costs depend on the amount of electricity produced by a given technology. The difference between the amount of electricity supplied or produced will be discussed below.

Firms maximise profits, although they cannot maximise profits unrestrictedly. There are three constraints that firms have to consider. First of all, the production of electricity is limited to the maximum operational electricity capacity owned by the firm. Since one of our main interests is to evaluate the environmental impacts, we focus on production of electricity and we ignore firms that only trade electricity. This does not rule out trade between countries, which is accompanied by the second restriction: the maximum capacity of the interconnections between countries. Finally, we include the possibility to impose emission restrictions on the production of electricity. Before we derive the three constraints of the model, we first define a number of identities.

3.1 Identities

There are three 'identities' in the static model. Firstly, we define the regional demand $S_{r,l}$ for electricity per load period. The demand function is a Constant Elasticity of Substitution (CES function) which depends on the elasticity parameter $\varepsilon_{r,l}$, the reference demand $d^0_{r,l}$ and a reference price $p^0_{r,l}$. The price elasticity of demand is then $-\varepsilon_{r,l}$. We assume that regional electricity market clear due to market prices. The demand function is as follows:

$$S_{r,l} = \sum_{f\in F} s_{f,r,l} = d^0_{r,l}\left(\frac{p_{r,l}\left(S_{r,l}\right)}{p^0_{r,l}}\right)^{-\varepsilon_{r,l}} \tag{3.2}$$

Secondly, due to the distribution of electricity, there are transportation losses which are a share of the production, denoted by $\lambda_{r*,r}$, where firm *f* is located in region $r*$. If a firm *f* located in region $r*$ exports $s*$ units of electricity to region *r* during peak hours, it has to produce $s^*/(1-\lambda_{r^*,r})$ units of electricity. More generally, the supply of electricity is a fraction of electricity production, where firm *f* is located in region *r**:

$$s_{f,r,l} = \left(1-\lambda_{r^*,r}\right)\sum_{i\in I} q_{i,f,r,l} \tag{3.3}$$

Thirdly, the regional market shares of firm *f* during load period *l* are given by:

$$\vartheta_{f,r,l} = \frac{s_{f,r,l}}{\sum_{g\in F} s_{g,r,l}} \tag{3.4}$$

Firm *f* does not necessarily have to be located in region *r*, because we allow firms to trade across borders, as we will discuss later on.

3.2 Constraints

Next to the identities, the model considers three different restrictions: two capacity constraints on production and trade, and one (optional) environmental constraint on emissions. The electricity production per technology of a firm *f* is restricted. The constraints are due to physical constraints (technologies using incineration) or due to climate conditions (wind or solar power). Therefore, there is an upper bound to the production capacity. This upper bound is complementary to the shadow price $\mu_{i,f,l}$, which obtains a nonnegative value as soon as the production with technology *i*, by firm *f*, during load period *l*, is equal to the maximum capacity:

$$\sum_{r\in R} q_{i,f,r,l} \le q_{i,f}^{\max} \perp 0 \le \mu_{i,f,l} \tag{3.5}$$

Due to the liberalisation of the electricity market, firms have the opportunity to export their electricity to other countries. However, the maximum amount of electricity export is limited with respect to the interconnection capacity between two countries. The amount of net export between the countries *r** and *r* is the exported amount of electricity from region *r** for region *r* minus the imported amount of electricity entering region *r** from region *r*, where firm *f* is located in country *r** ($f \in F_{r^*}$):

$$x_{r^*,r,l} = \sum_{f\in F_{r^*}} s_{f,r,l} - \sum_{g\in F_r} s_{g,r^*,l} \tag{3.6}$$

These exports are restricted too, which is complementary to shadow price $\tau_{r,r^*,l}$. As is usual with mixed complementary conditions, the shadow price of trade is zero, when the trade restriction is not binding:

$$x_{r^*,r,l} \le \eta_{r^*,r} \perp 0 \le \tau_{r^*,r,l} \tag{3.7}$$

If $x_{r^*,r,l}$<0, then country *r** imports electricity from county *r*. We do not impose a restriction on net imports of country *r**, because those are implicitly imposed by the export restrictions of other countries. In such a way, the import and export capacity of interconnections can differ. We assume that there is no ‘trade’ restriction on electricity produced and consumed within a country.

As a further extension/restriction of the model, emissions constraints can be added as well. For instance, due to the Kyoto protocol and various other kinds of environmental legislation, firms have to be careful to stay under the emission limits. This constraint can be included in the model by delimiting the total amount of emissions, where shadow price κ_k is nonzero as soon as the current amount of emissions is equal to a predefined emission ceiling:

$$Em_k = \sum_{l\in L} h_l \sum_{r\in R} \sum_{i\in I} \sum_{f\in F} \sigma_{i,r^*,k} q_{i,f,r,l} \le E_k \perp 0 \le \kappa_k \tag{3.8}$$

Emission factors are associated with the region of electricity production of firm *f* rather than the region of supply.

3.3 Profit maximisation in the electricity market

Since we assume a liberalised electricity market, we assume all firms to maximize profits: The operating profit function is summarized by the profit function in (3.1) with the identity in (3.3), and it is subjected to the production capacity constraint in (3.5), the trade constraint in (3.7), and the emission constraint in (3.8). Thus, the operating profit of the electricity producer *f* located in country r^* reads (note that this is the Lagrangian of the optimisation problem):

$$\begin{aligned}\Pi_f = &\sum_{l\in L} h_l \sum_{r\in R}\left(p_{r,l}\left(S_{r,l}\right)\left(1-\lambda_{r^*,r}\right)\sum_{i\in I} q_{i,f,r,l}\right) - \sum_{l\in L} h_l \sum_{r\in R}\left(\sum_{i\in I} c^{\mathrm{v}}_{i,r^*} q_{i,f,r,l}\right)\\ &-\sum_{l\in L} h_l \sum_{i\in I}\mu_{i,f,l}\left(\sum_{r\in R} q_{i,f,r,l} - q^{\max}_{i,f}\right)\\ &-\sum_{l\in L} h_l \sum_{\substack{r\in R,\\ r\ne r^*}} \tau_{r^*,r,l}\left(x_{r^*,r,l}-\eta_{r^*,r}\right)\\ &-\sum_{k\in K}\kappa_k\left(\sum_{l\in L} h_l \sum_{r\in R}\sum_{i\in I}\sum_{f\in F}\sigma_{i,r^*,k} q_{i,f,r,l} - E_k\right).\end{aligned} \tag{3.9}$$

Since the restrictions are inequalities rather than equalities, we have to derive the Kuhn-Tucker conditions of maximising an objective function. The first-order condition can be derived from the profits in (3.9) by taking the derivative with respect to the production of electricity $q_{i,f,r,l}$ for firm *f* located in country r^* ($f \in F_{r^*}$) and by setting the expression to 0:

$$\begin{aligned}&\left(1-\lambda_{r^*,r}\right)\left(p_{r,l}\left(S_{r,l}\right)\left[1-\frac{\vartheta_{f,r,l}}{\varepsilon_{r,l}}\right]\right) - c^{\mathrm{v}}_{i,r}\\ &-\mu_{i,f,l}\\ &-\left(1-\lambda_{r^*,r}\right)\tau_{r^*,r,l}\\ &-\sum_{k\in K}\kappa_k\sigma_{i,r^*,k}\\ &= 0.\end{aligned} \tag{3.10}$$

To complete the Kuhn Tucker conditions, we have the constraints in (3.5), (3.7), and (3.8), the non-negativity restriction on all shadow prices the amount of electricity produced $q_{i,f,r,l}$, and finally the identities in (3.2), (3.3), (3.4) and (3.6).

So far, we have not elaborated on the cost of electricity production. In economic models, production functions are usually well-defined functions (convex, continuous and differentiable). In the EMELIE model, however, the production costs differ across technologies and countries. In fact, the production functions are step functions with respect to variable costs (technology), but they also include the dimensions of supply regions and load periods. The marginal costs function of producing a unit of electricity can be derived from (3.10):

$$c^{\mathrm{m}}_{i,f,r,l} = c^{\mathrm{v}}_{i,r*} + \mu_{i,f,l} + \left(1-\lambda_{r*,r}\right)\tau_{r*,r,l} + \sum_{k\in K}\kappa_k\sigma_{i,r*,k}. \tag{3.11}$$

The first term on the right-hand side in (3.11) the production costs of supplying electricity. Note that the production costs of one unit of electricity supply are equal to the variable production cost corrected for transmission losses. The second and third term on the right hand side in Equation (3.11) are respectively the shadow prices of maximum production capacity per technology and the restrictions of trade. The fourth term on the left-hand side in Equation (3.12) represents the addition to the production cost due to emission factors associated with the related technology.

We use a MCP approach in which the marginal costs are implicitly determined by the model. However, we need a criterion to determine whether or not a firm is willing to produce electricity. This criterion is that the marginal revenue of electricity production has to be equal to or greater than the marginal cost of production. From (3.10), we derive the single MCP equation in terms of $q_{i,f,r,l}$,:

$$\left(1-\lambda_{r*,r}\right)p_{r,l}\left(S_{r,l}\right)\left[1-\frac{\vartheta_{f,r,l}}{\varepsilon_{r,l}}\right]-c^{\mathrm{m}}_{i,f,r,l} \geq 0 \perp 0 \leq q_{i,f,r,l} \tag{3.12}$$

The marginal costs are as defined in (3.11). This inequality is complementary to the level of electricity production with technology *i*, at firm *f*, to be delivered in region *r*, during load period *l*. This means that a nonnegative production is profitable as long as the marginal cost of electricity produced by firm *f* during load period *l* is equal to or lower than the marginal revenues.

3.4 Different types of firm behaviour

The first term on the left hand side in Equation (3.13) represents the marginal income from electricity sales within a regional market for a particular load period. The optimal amount of sales depends upon firms' type of behaviour. For instance, the marginal revenue from regional electricity sales is lowered by a market-power mark-up (ϑ/ε) in Equation (3.12). This is the case of quantity competition, which we refer to as the STRA scenario.

The monopoly mark-up can also be zero. This is the case of price competition, which we refer to as the COMP scenario. This leads to the following first order condition:

$$\left(1-\lambda_{r*,r}\right)p_{r,l} - c^{\mathrm{m}}_{i,f,r,l} \geq 0 \perp 0 \leq q_{i,f,r,l} \tag{3.13}$$

It is also possible to extend the static model with an alternative firm behaviour. Let us consider the case where one firm is a leader and considers the possibility of moving first, assuming that the (re)action of other firms is determined by equation (3.12). The action of the leading firm can then be modified, by scaling the monopoly mark-up, as follows:

$$\left(1-\lambda_{r^*,r}\right)p_{r,l}\left(S_{r,l}\right)\left[1-\xi_{f,l}\frac{\vartheta_{f,r,l}}{\varepsilon_{r,l}}\right]-c^{\mathrm{m}}_{i,f,r,l}\geq 0\perp 0\leq q_{i,f,r,l} \tag{3.14}$$

where $\xi_{f,l}$ is a fraction between zero and one, which lowers the monopoly mark-up of the leader. The consequence for leading firm f of setting $\xi_{f,l}$ is that firm f is able to increase its payoff, by increasing production during load type l, while the reaction of other firms is to lower their production somewhat and see a reduction in their payoffs.[5] We refer to the case where the leader chooses factor $\xi_{f,l}$ in such a way to maximise its payoffs as the STACK scenario. Payoffs or profits are defined as the difference between incomes from all regional sales minus the total cost of production:

$$\Pi_f=\sum_{l\in L}h_l\sum_{r\in R}\left(p_{r,l}\left(S_{r,l}\right)s_{f,r,l}-\sum_{i\in I}c^{\mathrm{v}}_{i,r^*}q_{i,f,r,l}\right) \tag{3.15}$$

Hence, the static EMELIE model consists of 8 variables ($q_{i,f,r,l}$, $\tau_{r,r^*,l}$, $\mu_{i,f,l}$, κ_k, $s_{f,r,l}$, $\vartheta_{f,r,l}$, $p_{r,l}$, $x_{r,r^*,l}$) and 8 equations (times the indices), namely (3.2)–(3.8), (3.14). Moreover, there is a set of firms F located in R different regions or countries. Furthermore, we consider a number of emissions, K and load types, L.

3.5 Cross-ownership

So far, we have implicitly assumed that firms are independent and act independently. The only possible strategic behaviour is reflected in the reaction curves of (independent) individual firms. However, firms can also act strategically in a different way, namely by acquiring other electricity producing companies. This acquisition is not limited to the domestic country of acquiring firms. Especially, the quickest way for firms to get a market share at foreign markets is to take-over a foreign company or to purchase assets of foreign firms.

In that case, the parent company (the firm holding assets of other firms) maximises profits from its own production activities as well as it takes into account – part of – the profits of its – partly – owned companies. Amundsen and Bergman (2002) have assessed the impact of this cross-ownership in the electricity market. There are two types of ownership: active and passive cross-ownership. In the case of active ownership, parent companies use the subsidiaries to exercise their power in order to enlarge their market share. The effect on the reaction curve resulting from the first-order condition is rather complicated. In the case of passive cross-ownership, parent companies take into account the value of subsidiaries, while in the case of active cross-ownership parent companies

---

5 It is not possible to get an explicit algebraic expression for the value of $\xi_{f,l}$ for firm f. The appropriate value, at present, can be derived numerically. This extension of the model shows how a first-move-advantage can be captured.

allocate the electricity capacity of subsidiaries in order to enlarge market shares and subsequently market power.[6]

Similar to Amundsen and Bergman (2002), we assume passive ownership in the EMELIE model, so that firm *f* maximises its value instead of its profit. Although this type of cross-ownership seems rather simplistic, passive cross-ownership does take into account all cross-ownership relations.

The value of firm $f(V_f)$ is defined as the profit of firm *f* plus the sum of ownership fraction times the value of other firms:

$$V_f = \Pi_f + \sum_{g \neq f} \delta_{f,g} V_g \tag{3.16}$$

where $\delta_{f,f} = 0$ by definition, and $0 \leq \delta_{f,g} \leq 1$ for $f \neq g$, and Π_f is the profit of function *f* as defined in (3.9). If firm *f* does not hold any assets of other firms, then the value of firm *f* is equal to its profit, i.e $V_{\mathrm{f}} = \Pi_f$. From (3.16), we can see that the total value of firm *f* is defined irrespectively from the location of the – partly – owned firms partly owned. For convenience, we can also use matrix notation for the value of firms:

$$V = \left[I - D\right]^{-1} \Pi \tag{3.17}$$

where V and Π are vectors of values of firms and profits of firms respectively, and D is the matrix of cross-ownership shares. We define $d_{f,g}$ as the elements of the matrix $[I–D]^{-1}$. If all firms are independent (no cross-ownership at all), the values of each firm is equal to it profit, i.e. $V = \Pi$. Now, we can express the value of firm *f* as a function of profits of all other firms:

$$V_f = \sum_{g \in F} d_{f,g} \Pi_g \tag{3.18}$$

Firm *f* now maximizes its value from (3.18). The first-order conditions follow from substituting (3.9) into (3.18) for all firms and then by taking the first derivative with respect to $q_{i,f,r,l}$. The first-order condition then reads

$$\left(1 - \lambda_{r*,r}\right) p_{r,l}\left(S_{r,l}\right)\left[1 - \sum_{g \in F} \frac{d_{f,g}}{d_{f,f}} \frac{\vartheta_{g,r,l}}{\varepsilon_{r,l}} \xi_{f,l}\right] - c^{\mathrm{m}}_{i,f,r,l} \geq 0 \perp 0 \leq q_{i,f,r,l} \tag{3.19}$$

With respect to the first-order condition in (3.14), the market power mark-up has changed slightly. Hence, to assess the impact of passive cross-ownership in a liberalised electricity market we only need to known the matrix of cross-ownership shares.

6 Due to the fact that active cross-ownership will increase the complexity of the model considerably, we ignore this type of cross-ownership for the time being.

4. Scenarios of electricity producer behaviour

With the EMELIE model, as presented in the Chapter 3, we can study economic and environmental consequences of the electricity market under different types of producer behaviour. Two aspects are essential to distinguish different types of producer behaviour, namely strategic behaviour of firms and cross-ownership between firms. In this section we discuss five different scenarios of producer behaviour, which we will use for our EMELIE model simulations and sensitivity analysis. The differences between the scenarios is reflected in the different values of the market power mark-ups ($\xi_{f,l}$) in equation (3.14). Table 4.1 summarizes the (ranges of) values of the market power mark-ups of the different scenarios.

Table 4.1 Scenarios of market behaviour of electricity producers in the EMELIE model.

Firms	REF/COMP	STRA	STACK	CROSS
Competing firms per country	$\xi_{f,l}=0$	$\xi_{f,l}=1$	$\xi_{f,l}=1$	$\xi_{f,l}=1$
One of theses competing firms sets production			$0\leq\xi_{f,l}\leq1$	
Some competing firms have cross ownership				$-1\leq\xi_{f,l}\leq1$
Fringe (non-competing firms)	$\xi_{f,l}=0$	$\xi_{f,l}=0$	$\xi_{f,l}=0$	$\xi_{f,l}=0$

With the data of the EU8 countries for the year 2000 as discussed in Chapter 2, the EMELIE model is calibrated. In the calibration, we assume that firms minimise cost, take (reference) prices as given and serve given demand (supply meets demand). We refer to this scenario as the reference (REF) scenario. In fact, this scenario reflects the accuracy of the EMELIE model. It is hard to give an interpretation to the REF scenario for two reasons. Firstly, the implementation of the liberalisation process of the national electricity markets is in progress in most countries of the EU. Secondly, most electricity markets are regulated markets, so that the prices do not reflect appropriate market prices for electricity.

The second scenario is the ideal focal point and the best achievable outcome of liberalisation, in terms of the lowest retail prices. No single electricity producer can exercise any market power. In other words, all firms act as a price taker (for all firms $\xi_{f,l}$=0), and they produce at marginal cost. This is the case of full competition, and we refer to this scenario as COMP scenario.

In a liberalised market, there is also a possibility that large firms will exercise market power, or act strategically. We consider three strategic competition scenarios: STRA, STACK, and CROSS. In the STRA scenario, large firms set quantities of supply by exercising market power. Due to the market power, firms will supply electricity at higher prices than the marginal costs, so that the supply curves in Figure 4.1 become steeper. All strategically acting firms exercise market power in a similar way ($\xi_{f,l}$ =1) and others (fringe) do not ($\xi_{f,l}$ =0). Note that we ignore any possible cross-ownership relations.

Next, the strategically competing firms in the STRA scenario are assumed to act similarly in the STACK scenario as well. Different from the STRA scenario, however, one competing firm is expected to behave as a price fighter. In fact, the price-fighting firm can foresee the reaction curves of its competitors, so that it can set production in order to enlarge its production, and consequently its market share and profits. The value of $\xi_{f,l}$ of this firm is in the range from 0 to 1, while the strategically competing firms have $\xi_{f,l}$ =1, and the non-competing firms have $\xi_{f,l}$ =0.

Based on the available production capacity, EdF (France) is the largest firm in the EU8, and it would be logical to assign EdF as a market leader. However, simulations with the EMELIE model have shown that EdF can hardly benefit from being a market leader, because it has no competitors in the French market. Therefore, we choose RWE (Germany), because it is the second largest firm in the EU8, and it has competitors at its domestic market. We take RWE as the 'potential' market leader in this report to show the consequences for one of the many possible STACK scenarios. We acknowledge that the choice of any other firm to become market leader will affect the results of this scenario.

Finally, we study the CROSS scenario. In fact, the CROSS scenarios is similar to the STRA scenario with one extension. Firms consider cross-ownership relations as well. Thus, firms maximise their values rather than their profits. The value of $\xi_{f,l}$ of firm with cross-ownership relations can be derived from the model ex-post and it is in the range from –1 to 1, while the competing firms without cross-ownership relations have $\xi_{f,l}$ =1, and the non-competing firms have $\xi_{f,l}$ =0.

Figure 4.1 present the electricity market equilibriums for the different scenarios REF, COMP, STRA and STACK. In the EMELIE model we assume that markets clear through a market-clearing price. The decreasing curve in Figure 4.1 represents consumer demand, which is fixed in each situation. The increasing curves in Figure 4.1 represent marginal supply curves, which can be pushed up by exercising market power, leading to various equilibria in the electricity market.

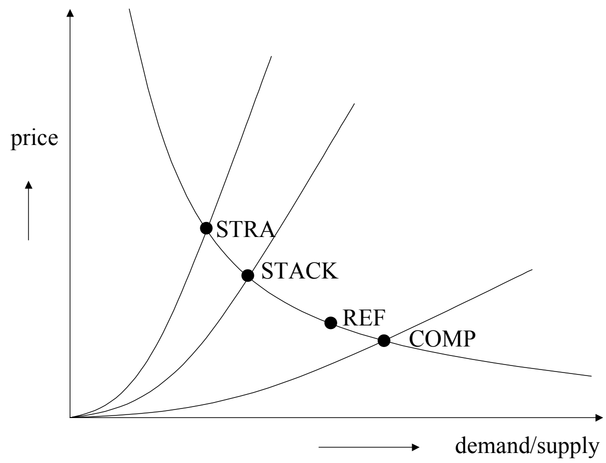

Figure 4.1 Demand and supply for various types of firm equilibrium behaviour.

5. Results

The liberalisation process will change the performances of electricity markets. Policy makers believe that more competition between electricity producers will lower the costs of electricity production, which will subsequently lower the market prices. The question remains, however, how will electricity producers eventually behave in a liberalised market? With the EMELIE model, we try to gain more insights in the mechanism of a 'European-wide' liberalised electricity market.

Below, we discuss the results of the EMELIE model for five different scenarios as discussed in Chapter 4. The REF scenario is the reference case in which the national – regulated – electricity markets in 2000 are replicated with the EMELIE model by minimizing production costs given the electricity prices and the demand for electricity. The second scenario has full competition in the electricity market (COMP), where all electricity producers act as price takers. The third scenario is the case where large firms act strategically and simultaneously, while the fringe continues to be fully competitive. The reaction curve of the strategically acting firms is given by equation (3.14) with $\xi_{f,l}$=1 and $\xi_{f,l}$=0 for the fringe. In the STACK scenario, RWE (Germany) behaves as a price fighter, while the other firms follow a similar behaviour as in the STRA scenario. In particular, RWE foresees how its competitors behave in the electricity market and it allocates its production in such a way that it enlarges its market share and profits. The value of $\xi_{RWE,l}$ is within the range form 0 to 1 given its reaction curve in (3.14). Finally, we present the CROSS scenario, in which firms maximize their values instead of their profits.

In Chapter 2, we discussed the data for the calibration of the EMELIE model. In addition, the EMELIE model requires also information on price elasticities and the division of prices and demand between load periods. Except for Denmark and the Netherlands, in which the electricity of demand is assumed to be somewhat more price inelastic (–0.29), the price elasticity of demand is assumed to be –0.4, as in Lise et al. (2003). One might argue that this value of price elasticity is rather high, but by following the survey of Pineau and Murto (2003), a price elasticity of –0.4 reflects the alternatives for consumers to choose its electricity supplier abroad. Following Pineau and Murto (2003), we assume that the (regional) price elasticity of electricity demand for peak load is twice the elasticity of demand for base load. This assumption implies that the demand for peak load is more elastic than for base load.

Table 5.1 shows the reference demand and reference price for the eight national electricity markets in 2000. In the model we consider two load periods, namely peak and base load, and consequently we consider different demand functions for both load periods.

Per year there are h = 365*24 = 8,760 load hours to be served. We assume that 20% of the year concerns peak load h_{peak} = 1,752 hours and the remaining 80% of the year concerns base load h_{base} = 7,008 hours. In addition, we assume that demand at peak hours in region r requires 90% of total available capacity: $d^0_{r,\text{peak}} = 0.9\ \Sigma_f \Sigma_i q^{\max}_{i,f}$ for all $f \in F_r$

Table 5.1 Reference price and reference demand per load period in 2000.

	BEL	DEN	FIN	FRA	GER	NLD	NOR	SWE
Prices (€/MWh)								
Average	39.65	17.41	14.88	20.81	18.19	39.65	12.25	14.26
Peak load	35.69	15.67	13.39	18.72	16.37	35.69	11.03	12.83
Base load	51.67	19.69	19.04	24.68	23.29	52.01	16.49	18.06
Demand (GW)								
Total	9.04	3.75	8.72	46.88	54.45	11.48	12.66	15.46
Peak load	8.49	2.66	8.03	38.14	50.17	10.87	12.28	14.06
Base load	11.21	8.11	11.49	81.83	71.56	13.94	14.20	21.07

Also, we assume that the price of electricity under base load is 90% of the average price: $p^0_{r,\mathrm{base}} = 0.9\, p^0_r$. Then, the reference demand at base hours, $d^0_{r,\mathrm{base}}$, and the reference price of electricity at peak hours, $p^0_{r,\mathrm{peak}}$, are derived by the following two demand and price balance equations and the results are presented in Table 5.1:

$$d^0_{r,\mathrm{base}} = \frac{d^0_r h - d^0_{r,\mathrm{peak}} h_{\mathrm{peak}}}{h_{\mathrm{base}}} \tag{5.1}$$

$$p^0_{r,\mathrm{peak}} = \frac{p^0_r d^0_r h - p^0_{r,\mathrm{base}} d^0_{r,\mathrm{base}} h_{\mathrm{base}}}{d^0_{r,\mathrm{peak}} h_{\mathrm{peak}}} \tag{5.2}$$

This section discusses the results of the five scenarios of the EMELIE model. First, we discuss the impact of the liberalisation process on the –domestic– electricity markets. Then, we discuss the impact on the performance of individual firms, and finally we discuss the environmental consequences of market liberalisation.

Table 5.2 shows the resulting prices and supply in the EU8 for the five different scenarios. The total electricity supply in the EU8 is 1,423 TWh at an average price of €20.62 per MWh (REF scenario). The average electricity prices differ across countries, where Belgium and the Netherlands have a high price of almost €40, and Norway has the lowest price of €12.25. Since costs are minimized given total electricity demand, the electricity prices reflect the variable costs of production present in the country. Electricity production in Norway, for instance, consist primarily of cheap hydropower, while Belgium and the Netherlands electricity production relies on the use of more expensive fossil fuels based technologies; see Table 2.5 with the overview of the electricity capacity.

In the COMP scenario, all electricity producers act as price takers, which means that they produce electricity regardless of the electricity supply of their competitors and given the market price. Then, total electricity supply increases, while the average electricity price in the EU8 decreases. In the COMP scenario, the electricity supply in Belgium, France, and the Netherlands increases, while the electricity prices decline in comparison with the REF scenario. In the REF scenario, the electricity prices in these three countries were the highest. Probably, for these countries it becomes cheaper to import from abroad, so that prices decline and supply increases. In the other countries, we see the opposite development. Prices increase and supply decreases in the COMP scenario in comparison with the REF scenario.

Table 5.2 Electricity prices and electricity supply during different load periods for five scenarios.

	Electricity prices (€/MWh)					Electricity supply (TWh)				
Region	REF	COMP	STACK	STRA	CROSS	REF	COMP	STACK	STRA	CROSS
	Total									
BEL	39.65	26.88	38.07	38.01	33.22	79.2	96.1	83.2	83.3	87.8
DEN	17.41	18.02	18.46	18.46	18.26	32.9	31.9	31.5	31.5	31.6
FIN	14.88	15.38	16.90	16.90	16.79	76.4	74.7	71.4	71.4	71.4
FRA	20.81	13.19	25.65	25.89	25.86	410.7	503.5	363.2	362.3	362.3
GER	18.19	18.47	23.47	26.11	26.02	477.0	464.0	418.0	399.4	400.0
NLD	39.65	27.13	34.27	33.71	32.30	100.6	115.6	106.7	107.3	109.0
NOR	12.25	13.56	15.35	15.35	15.11	110.9	104.6	98.7	98.7	99.3
SWE	14.26	15.28	17.23	17.23	16.68	135.4	129.0	122.1	122.1	123.9
EU8	20.62	17.14	24.22	25.07	24.55	1423.0	1519.3	1294.6	1275.8	1285.5
	Base load period									
BEL	35.69	22.91	38.14	38.14	31.26	59.6	71.1	58.0	58.0	62.8
DEN	15.67	13.99	14.19	14.19	13.99	18.6	19.3	19.2	19.2	19.3
FIN	13.39	13.51	15.12	15.12	14.87	56.3	56.1	53.6	53.6	54.0
FRA	18.73	7.91	22.36	22.85	22.76	267.3	377.4	249.0	246.9	247.2
GER	16.37	15.13	21.24	24.57	24.46	351.6	362.9	316.9	298.9	299.4
NLD	35.69	23.89	31.82	31.13	29.85	76.1	85.5	78.7	79.2	80.2
NOR	11.03	11.83	13.70	13.70	13.42	86.0	83.6	78.9	78.9	79.5
SWE	12.83	13.00	15.24	15.24	14.60	98.5	98.0	92.0	92.0	93.6
EU8	18.60	13.38	21.75	22.91	22.24	1014.0	1153.8	946.2	926.6	936.0
	Peak load period									
BEL	51.67	38.14	37.91	37.73	38.14	19.6	25.1	25.2	25.3	25.1
DEN	19.69	24.20	25.13	25.13	24.92	14.2	12.6	12.3	12.3	12.4
FIN	19.04	21.02	22.26	22.26	22.70	20.1	18.6	17.8	17.8	17.5
FRA	24.69	28.98	32.81	32.39	32.52	143.4	126.1	114.2	115.4	115.0
GER	23.29	30.47	30.47	30.70	30.67	125.4	101.1	101.1	100.5	100.6
NLD	52.01	36.35	41.18	40.98	39.12	24.4	30.1	28.0	28.1	28.8
NOR	16.49	20.46	21.91	21.91	21.92	24.9	20.9	19.8	19.8	19.8
SWE	18.07	22.48	23.30	23.30	23.08	36.9	31.0	30.1	30.1	30.3
EU8	25.64	29.02	30.92	30.83	30.75	409.0	365.5	348.5	349.2	349.5

Note: The average EU8 prices are the domestic market prices weighted by the share of domestic supply in total EU8 supply.

In the other scenarios (STACK, STRA and CROSS), the electricity price is considerably higher, and consequently the electricity supply is lower than in the reference scenario. The results for the national electricity markets vary slightly. Except for Belgium and the Netherlands, the electricity prices increase in all strategic competition scenarios, while the supply of electricity declines. For Belgium and the Netherlands, prices decline if electricity producers act strategically, which is probably due to the high initial market price for electricity (REF scenario). For both countries, market prices in the STACK, STRA and CROSS-scenarios are higher than in the COMP scenario.

If we compare the average prices in the COMP scenario with those in the STRA scenario, we clearly see a general price increase in all national markets in the STRA scenario, which indicates that competing firms exercise their market power. This result corresponds to our expectation as represented in Figure 4.1. In comparing the STACK scenario with STRA, we see that the prices increase in all market except for the German market where the leader is situated. The difference between CROSS and STRA is more mixed. While the prices go down in relatively small markets of the Benelux, they go up in the other 6 markets. This shows that acquisition of passive cross-border ownership increases the possibility for executing market power.

5.1 Load periods

The EMELIE model distinguishes two load periods as defined in Chapter 2. In the REF scenario, the electricity prices for the peak load period are higher than for base load period. The prices in the base load period range from €11.03 (Norway) to €35.69 (Belgium and the Netherlands), while the prices range from €16.49 (Norway) to €52.01 (the Netherlands) in the peak load period.

In the case of the COMP scenario, prices in the base load period decline in all countries except for Norway, Sweden and Finland. For instance, in Norway, the prices increase from €11.03 (REF) to €11.83 (COMP). The explanation is probably that Norwegian, Swedish and Finnish market have the lowest initial prices and that companies have an incentive to export electricity to countries with higher initial market prices, so that the supply for the domestic market has to be satisfied with more expensive peak load technologies or with rather expensive imports. Countries such as Belgium and the Netherlands realise a relatively large price reduction in the base load periods in the COMP scenario in comparison with the REF scenario. Overall, the electricity price in the base load period in the COMP scenario is lower than in the REF scenario.

For the electricity price in the peak load period (COMP scenario) we observe a similar development, although next to Norway, Denmark, Finland, France, Germany and Sweden, face price increases in the peak load period as well. Moreover, the price increases are substantial. Only Belgium and the Netherlands have lower prices, but again their initial prices in the REF scenario were considerably higher than in the other countries. Moreover, due to cross-border competition the variation of the peak load prices between countries is reduced. The remaining variation in peak load prices can be attributed to the fact that there are binding constraints (electricity capacity and interconnection capacity).

With respect to the scenarios dealing with strategically acting firms, the impact of liberalisation on the base load prices is ambiguous. In comparison to the STRA scenario, the base load prices decline in France and Germany and increase in the Netherlands in the STACK scenario, while the prices in the other countries are unaffected. In the STRA case, only the base load price in the Netherlands is below the level of the REF scenario. Finally, in the CROSS scenario, the base load price of electricity declines for all countries in comparison with the STRA scenario.

In the case of peak load prices, the prices in the strategic competition scenarios increase compared to the REF scenario except for Belgium and the Netherlands. However, the reference price in the peak load period is extremely high in both countries. In comparison to the STRA scenario, the peak load prices only declines in France and increase in the Netherlands, Germany as well as Belgium in the STACK scenario. As for base load prices, the prices in the other countries are unaffected. In the CROSS scenario, the peak load price of electricity declines for Denmark, Germany, the Netherlands and Sweden, while the peak load price increases for Belgium, Finland, France and Norway in comparison with the STRA scenario. In the peak load period, prices and supplies show little variation between the three strategic competition scenarios (STACK, STRA and CROSS).

5.2 Price decomposition

In the previous section, we analysed the outcome of the EMELIE base run with the market equilibrium prices of electricity in five different scenarios. However, by taking a further look at the first order optimality condition of the EMELIE model (equation (3.11)), we can conclude that the level of the electricity price in equilibrium is not only driven by production costs, but also by on the one hand shadow prices of the different restrictions, and on the other hand, the market power executed by strategically acting firms. In fact, we can decompose the equilibrium electricity prices according to equation (3.11)

$$\left(1-\lambda_{r*,r}\right)p_{r,l}\left(S_{r,l}\right)\left[1-\xi_{f,l}\frac{\vartheta_{f,r,l}}{\varepsilon_{r,l}}\right]=c^{\mathrm{v}}_{i,r*}+\mu_{i,f,l}+\left(1-\lambda_{r*,r}\right)\tau_{r*,r,l}+\sum_{k\in K}\kappa_k\sigma_{i,r*,k} \qquad (5.3)$$

Hence, the price of electricity in region r during load type l times the market power mark-up ($\xi_{f,l}$=0 in COMP) is equal to the marginal cost of production plus the payment for capacity plus the trade cost plus the cost of emissions reduction. We call the average shadow price of the capacity constraint $\mu_{i,f,l}$ the capacity payments, because this shadow price represents the willingness to invest per technology, firm and load type and it is in a way the reserved price for owning the capacity which has been used in production during a particular load period.

In order to undertake a decomposition of the national market prices, we need to consider the weighted averages of the marginal production costs, and the shadow prices of capacity, trade and environment. An appropriate weight factor is the amount of production minus transmission losses. These data are available at the technology and firm level. Table 5.3 presents the result of such decomposition.

Inspection of Table 5.3 shows that the major share of the average market price comprises of the marginal production costs with a share around 2/3rd. The remaining third of the price comprises capacity payments and about 3% of the average market price consists of trade. This decomposition also provides us with a number of additional insights.

The marginal production costs increase in Belgium, France and Norway in comparison with the COMP scenario, while they increase in the other five national markets. Overall the marginal production costs increase somewhat. From this data we draw an interesting conclusion, namely that in the case of strategic competition (STACK, STRA, CROSS), electricity is not necessarily produced at the places where it is cheapest to do so, but firms with market power can distort the market. This distortion is of such a kind that while the total production is lower under the strategic competition scenarios, the total average marginal cost has risen above the cost of production under perfect competition.

Table 5.3 Decomposition of regional equilibrium prices per scenario.

€/MWh	Marginal production cost				Capacity payments				Trade costs			
Region	COMP	STACK	STRA	CROSS	COMP	STACK	STRA	CROSS	COMP	STACK	STRA	CROSS
	Total											
BEL	12.69	14.67	14.96	14.61	10.75	6.13	6.09	6.33	3.43	1.38	1.24	0.71
DEN	9.89	10.16	10.15	9.78	7.76	6.16	6.17	6.42	0.37	0.13	0.13	0.14
FIN	10.57	10.90	10.90	11.10	4.80	3.62	3.62	3.61	0.01	0.18	0.18	0.07
FRA	7.63	12.98	12.92	12.71	5.56	5.20	5.25	5.26	0.00	0.43	0.03	0.00
GER	11.12	10.66	10.95	10.88	7.18	5.52	5.56	5.48	0.18	0.31	0.45	0.54
NLD	17.64	18.54	17.95	18.29	7.64	6.59	7.03	6.15	1.85	2.60	1.65	1.79
NOR	5.93	8.41	8.41	8.19	7.63	5.39	5.39	5.50	0.00	0.00	0.00	0.00
SWE	4.91	4.05	4.05	4.09	10.37	9.69	9.69	9.64	0.00	0.00	0.00	0.00
EU8	9.62	11.42	11.48	11.40	7.10	5.85	5.92	5.85	0.42	0.54	0.38	0.38
	Base load period											
BEL	10.74	15.70	16.13	14.76	8.06	3.32	3.27	3.61	4.10	1.97	1.77	0.00
DEN	6.95	10.00	9.99	9.47	6.61	2.94	2.95	3.30	0.43	0.00	0.00	0.00
FIN	9.19	9.68	9.68	9.77	4.31	2.80	2.79	2.84	0.01	0.22	0.22	0.09
FRA	6.57	12.72	12.69	12.56	1.34	2.70	3.08	3.16	0.00	0.63	0.00	0.00
GER	10.67	10.09	10.37	10.31	4.29	3.61	4.02	4.03	0.17	0.28	0.46	0.56
NLD	16.33	17.64	16.85	17.37	5.36	4.70	5.52	4.37	2.19	2.84	1.54	1.80
NOR	5.13	7.49	7.49	7.30	6.70	4.55	4.55	4.61	0.00	0.00	0.00	0.00
SWE	4.47	2.93	2.93	2.99	8.53	8.66	8.66	8.55	0.00	0.00	0.00	0.00
EU8	8.69	10.82	10.87	10.77	4.21	3.95	4.26	4.22	0.48	0.63	0.40	0.34
	Peak load period											
BEL	18.23	12.30	12.26	14.26	18.38	12.61	12.55	13.14	1.53	0.00	0.00	2.50
DEN	14.40	10.40	10.40	10.27	9.51	11.19	11.19	11.29	0.29	0.33	0.33	0.35
FIN	14.73	14.58	14.58	15.22	6.29	6.11	6.11	5.98	0.00	0.08	0.08	0.04
FRA	10.80	13.52	13.42	13.02	18.18	10.64	9.92	9.77	0.00	0.00	0.09	0.00
GER	12.72	12.44	12.67	12.58	17.54	11.53	10.13	9.78	0.22	0.42	0.43	0.46
NLD	21.35	21.09	21.04	20.85	14.12	11.91	11.28	11.11	0.88	1.94	1.97	1.78
NOR	9.12	12.09	12.08	11.78	11.34	8.72	8.73	9.10	0.00	0.00	0.00	0.00
SWE	6.29	7.46	7.46	7.49	16.20	12.82	12.82	13.01	0.00	0.00	0.00	0.00
EU8	12.55	13.06	13.09	13.09	16.22	11.01	10.31	10.23	0.25	0.29	0.33	0.47

The level of capacity payments is on average lower in the strategic competition scenarios than in the case with perfect competition. During base load an increase in the capacity payments is found in France and during peak load in Belgium.

The trade price is relatively easy to explain. There is a big incentive to export to markets with relatively high prices like Belgium and The Netherlands. Here we find the highest trade prices. In Norway and Sweden the trade price is even zero. Hence, the import constraint is never binding in these two countries and this implies that they have a strong incentive to sell their locally produced electricity abroad. It is also interesting to see that export to France during base load only takes place during the STACK scenario. This means that RWE, as market leader, has to find a market to sell the additionally produced electricity, increasing the trade price to France, but also to The Netherlands and indirectly to Belgium. Export to the German market becomes a somewhat less attractive option.

While the three shares of marginal production cost, capacity payments and trade add up to the equilibrium prices as reported in Table 5.2 for the COMP scenario, this is not the case for the STACK, STRA and CROSS scenarios. For these scenarios, the difference between the prices in Table 5.2 and the sum of marginal production costs, capacity payments and the trade costs derived from Table 5.3 are a proxy of the absolute price increase due to the market power in a national electricity market.

Table 5.4 presents these average market power mark-ups, which corresponds to $\xi(\vartheta/\varepsilon)$ in equation (5.3).

Table 5.4 Market power mark-up in the EU8 countries per scenario.

	Total			*Base load period*			*Peak load period*		
Region	STACK	STRA	CROSS	STACK	STRA	CROSS	STACK	STRA	CROSS
BEL	41.7%	41.4%	34.8%	45.0%	44.5%	41.3%	34.3%	34.2%	21.6%
DEN	10.9%	10.9%	10.5%	8.8%	8.8%	8.7%	12.8%	12.8%	12.1%
FIN	13.0%	13.0%	11.9%	16.0%	16.0%	14.6%	6.7%	6.7%	6.4%
FRA	27.4%	29.7%	30.5%	28.2%	31.0%	30.9%	26.3%	27.7%	29.9%
GER	29.7%	35.1%	35.1%	34.2%	39.6%	39.1%	20.0%	24.3%	25.6%
NLD	19.1%	21.0%	18.8%	20.9%	23.2%	21.1%	15.2%	16.3%	13.8%
NOR	10.1%	10.1%	9.4%	12.1%	12.1%	11.3%	5.0%	5.0%	4.7%
SWE	20.3%	20.3%	17.6%	24.0%	24.0%	21.0%	13.0%	13.0%	11.2%
EU8	26.4%	29.1%	28.2%	29.2%	32.2%	31.1%	21.2%	23.0%	22.6%

It clearly follows from Table 5.4 that the market power mark-up is on average higher in the base load than in the peak load. On the one hand, peak demand requires a large part of total production capacity, so that there remains ample room for competition, and on the other hand, we assume that elasticities of electricity demand in the peak load period are substantially higher than in the base load period. Furthermore, the market power mark-up is the highest in Belgium in all scenarios. This illustrates the monopoly position of Electrabel in Belgium. The monopolist in France (EdF) has the second highest market power mark-up during peak load, while the market power mark-up of Germany is second highest during base load, which also ranks Germany as the second highest overall. The Danish and Norwegian markets are the closest to perfect competition, with a market power mark-up of only 10%.

5.3 Individual firms

Table 5.5 shows the resulting discounted payoff per firm in million Euros. From Table 5.5 we can see that the leader (RWE) has an 11% higher payoff in STACK than in STRA, while other firms in Germany have substantially lower payoffs. This indicates that there is a first mover advantage when RWE is the market leader, but also that the reduction in market power mark-up is large (see also Table 5.5 for the ξ factor of the leader under base and peak load).

Table 5.5 Payoff and marginal costs per firm (Million euros) for five different scenarios

	Payoff: (Meuro/year)					Average marginal cost (€/MWh)			
Firm	REF	COMP	STACK	STRA	CROSS	COMP	STACK	STRA	CROSS
FrinBEL	189	99	205	204	154	27.36	38.09	38.06	32.72
ElectBEL	1,627	1,045	1,168	1,168	1,185	12.55	10.30	10.53	11.34
FrinDEN	85	86	92	92	89	17.71	16.38	16.38	16.27
ElsamE2	104	175	234	276	273	12.45	12.51	12.53	12.51
FrinFIN	156	195	238	238	237	15.72	17.22	17.22	17.20
Fortum	208	230	238	238	242	7.43	5.66	5.66	6.14
PVO	87	106	116	116	113	8.37	6.70	6.70	6.68
FrinFRA	106	238	728	753	750	23.85	24.64	24.93	24.89
EDF	5,678	3,320	5,401	5,702	5,560	6.80	6.70	6.70	6.70
FrinGER	175	263	445	547	543	18.67	24.07	26.59	26.51
EnBW	564	587	863	975	953	8.98	9.05	9.06	9.07
EONGER	1,281	1,157	1,548	1,872	1,902	9.88	7.58	9.18	9.35
VattenGER	628	697	1,070	1,317	1,291	11.63	11.27	11.86	11.86
RWE	**990**	**1,220**	**2,131**	**1,918**	**1,876**	11.20	12.18	10.53	10.46
FrinNLD	563	298	474	460	426	26.38	33.69	33.10	31.71
ElectNLD	256	118	233	229	183	21.49	22.35	22.37	22.36
NUON	320	150	262	259	213	17.84	16.98	17.00	16.80
EONNLD	194	82	190	187	142	19.63	20.27	20.29	20.21
Essent	598	291	459	427	373	16.96	15.65	15.89	15.92
FrinNOR	549	616	697	697	687	13.59	15.38	15.38	15.16
Statkraft	474	534	603	603	588	0.00	0.00	0.00	0.00
OsloEn	121	136	153	153	150	0.00	0.00	0.00	0.00
NorskHy	99	112	126	126	123	0.00	0.00	0.00	0.00
Agder	99	107	120	120	117	0.00	0.00	0.00	0.00
BKK	108	100	111	111	109	0.04	0.04	0.04	0.04
Lyse	89	98	108	108	106	0.00	0.00	0.00	0.00
FrinSWE	62	98	116	116	111	15.90	17.70	17.70	‘7.19
VattenSWE	655	746	754	767	759	4.91	4.10	4.10	4.25
Sydkraft	192	257	287	287	277	5.65	5.70	5.70	5.70
Birka	171	200	224	224	216	5.43	4.86	4.86	4.87
FortumK	55	71	82	82	79	3.58	3.56	3.56	3.56
Skellefte	39	38	43	43	41	2.86	2.82	2.82	2.83
Graninge	32	35	39	39	38	1.30	1.29	1.29	1.30
All firms	16,551	13,503	19,556	20,455	19,901	9.62	11.42	11.48	11.40

Note: The average marginal costs are weighed by the number of load hours, actual production minus transmissions losses. $\xi_{RWE,base}$=0.439; $\xi_{RWE,peak}$=0.000.

5.4 Environment

The EMELIE model can also measure the environmental impacts of different firm behaviours. In the REF scenario, the levels of emissions are 442 Mton CO_2 equivalents, 1,078 kton acid equivalents, and 2,871 kton PM10 emissions. The effect of different market behaviour scenarios on greenhouse gas, acidifying and smog emissions relative to the reference scenario is presented in Figure 5.1.

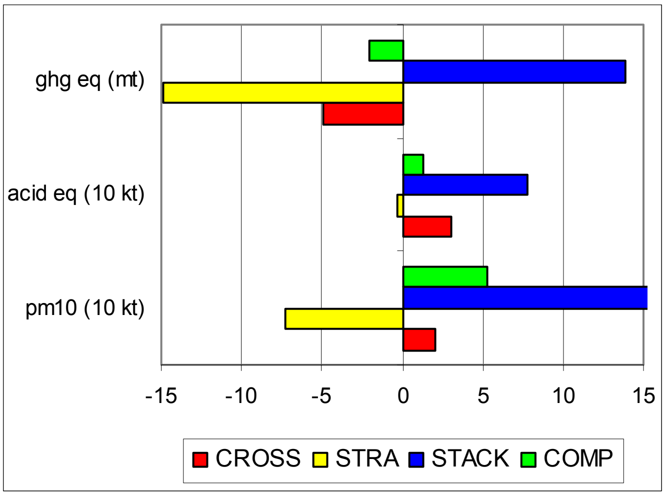

Figure 5.1 Changes in levels of emissions under different scenarios of producer behaviour.

Figure 5.1 shows that the difference in emissions with respect to the reference scenario point in the same direction for each pollutant for the STRA and STACK scenarios. The effect in the COMP and CROSS scenario is mixed. Under full competition or with cross-ownership relations, greenhouse gas emissions decline compared to the initial situation, while acidification and smog formation increase.

Let us consider the effect of firm behaviour on greenhouse gas emissions. It turns out that the reduction in the level of greenhouse gas emissions is the highest in the STRA scenario. As in the STRA scenario, greenhouse gas emissions are also lower in the COMP and CROSS scenarios as compared to the REF scenario. The main reason is that the level of electricity supply in these scenarios is much lower than in the REF scenario. The level of greenhouse gas emissions in the STACK scenario even increases with respect to the reference scenario. This is caused by the extra production of RWE, which is realised with an additional production with carbon-intensive lignite. Table 5.6 shows that the total production with lignite goes up in the STACK scenario to 85% of total capacity from 58% of total capacity in the STRA scenario.

Table 5.6 presents the use of technologies in the load periods. In the REF scenario, almost all technologies are fully used during the peak period, while the technology mix in the base load period shows a large variation. A similar trend is found for the COMP scenario. Due to the fact that the peak load supply in the COMP scenario is lower than in the REF scenario, the technologies Gas and CHP oil are not fully used. The higher base load supply in the COMP scenario is produced with the carbon-intensive technologies Coal and Lignite that show higher shares in the COMP scenario than in the REF scenario.

In the STACK scenario, the share of Lignite is 85% in the base load period, while the share of lignite in the STRA scenario is 58%. Recall that the main technology of RWE, the price leader in our STACK scenario, is Lignite, so that the technology results indicate the market power of RWE as well.

Table 5.6 Use of technology of firms per region under base and peak load.

	REF		COMP		STACK		STRA		CROSS	
Technology	Base	Peak	base	peak	base	peak	base	peak	base	peak
Nuclear	81%	100%	100%	100%	59%	100%	59%	100%	59%	100%
Coal	43%	100%	54%	100%	48%	82%	51%	82%	50%	82%
Lignite	73%	100%	72%	100%	85%	100%	58%	100%	68%	100%
Gas	0%	100%	0%	51%	8%	63%	8%	65%	7%	65%
Oil	0%	56%	0%	1%	0%	0%	0%	0%	0%	0%
CHP-gas	81%	100%	78%	100%	87%	100%	87%	100%	89%	100%
CHP-coal	100%	100%	100%	100%	97%	100%	97%	100%	97%	100%
CHP-oil	0%	100%	9%	46%	0%	46%	0%	46%	0%	46%
CHP-bio	0%	100%	35%	100%	20%	50%	24%	50%	24%	50%
CHP-others	0%	100%	0%	100%	72%	99%	72%	99%	72%	99%
Hydro	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Wind	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

In the peak load period, the results do not differ because the Lignite technology capacity is fully used. The results in the table also indicate that in the STACK, STRA and CROSS scenarios carbon-intensive technologies, such as Coal, are used less in peak load production, while ‘clean’ technologies, such as CHP others, are used more in base load production.

6. Sensitivity analysis

In order to assess whether the EMELIE model produces robust and reasonable results, we apply a sensitivity analysis. A number of key parameters are evaluated, such as the level of the price elasticity of the demand (ELASTIC), the ratio of price elasticities of base load and peak load demand (ELASTEQ), transmission losses (LAMBDA), distribution of peak load and base load demand (PEAKBASE), uniform electricity prices (UNIFORM) and trade options (TRANSM). We particularly focus attention on what the impact of model parameters is on the performance of national electricity markets in terms of market prices and electricity demand. Issues such as (de-)mergers and emission restrictions are beyond the scope of this sensitivity analysis. However, we consider two environmental scenarios (ENVIRON) as well. In the first of these ENVIRON scenarios, prices of emission permits from emission trading enter explicitly in the model as costs of production. In the second scenario, we assume that policy makers impose a binding restriction on GHG emission reduction of 10%. For all these sensitivity analyses, we consider the five scenarios REF, COMP, STRA, STACK and CROSS as in Chapter 5.

6.1 Transmission losses (LAMBDA)

Transmission losses, i.e. the parameters $\lambda_{r,r*}$ in the EMELIE model in Chapter 3, are the differences between production output and actual supply. According to Table 2.4, transmission losses differ across countries, where the transmission losses increase with the size of a country. Due to these characteristics of transmission losses, we evaluate alternative values in order to measure the impact on producer behaviour in the EU8 electricity market. In the STACK scenario, RWE remains the market leader, although the market power mark-ups of RWE are recalculated: ξ_{base} = 0.434 and ξ_{peak} = 0.270 in the case of lower transmission losses, and ξ_{base} = 0.458 and ξ_{peak} = 0.506 for higher transmission losses.

In particular, the impacts of transmission losses are evaluated by imposing a 25% increase and a 25% decrease on transmission losses. In general, the average electricity prices under all scenarios decrease due to lower transmission losses and increase due to higher transmission losses. In comparison with the results from the initially calibrated model in Table 5.2, the price in the COMP scenario declines from € 16.73 to € 16.48 due to lower transmission losses (–1.3%), and increases to € 16.94 due to higher transmission losses (1.3%). The other scenarios except the REF scenario show the similar trend for the average price as well for the base load and peak load price.

At the national level, which is not presented in the table, a similar trend is observed, although there is one exception. Under full competition, the electricity price in Norway slightly increases with lower transmission losses, and decreases with higher transmission losses. This is caused by changes in the imports of cheap nuclear energy from Sweden in this scenario. If transmission losses are higher, producers in Sweden are less willing to produce for the Norwegian electricity consumers, which is due to the high transmission losses in the Sweden and Norway.

As prices increase with the level of transmission losses, the demand for electricity, emissions and payoffs all decrease with the level of transmission losses. In general, the EMELIE model is robust for changes in the level of transmission losses. Note that variations in the transmission losses affect the utilisation ratio of production capacity in the REF scenario. Lower transmission losses lower the burden on production capacity.

Table 6.1 The EU8 electricity market for different scenarios with variation in the transmission losses.

	Transmission losses –25%					*Transmission losses +25%*				
Region	REF	COMP	STACK	STRA	CROSS	REF	COMP	STACK	STRA	CROSS
Price										
Average	20.62	16.75	23.55	24.41	23.92	20.62	17.47	24.83	25.73	25.22
Base	18.60	12.99	21.10	22.27	21.64	18.60	13.66	22.33	23.52	22.85
Peak	25.64	28.62	30.15	30.03	29.96	25.64	29.58	31.67	31.67	31.63
Demand										
Total	1423.0	1537.5	1313.4	1294.0	1303.0	1423.0	1503.4	1278.1	1258.7	1267.6
Base	1014.0	1168.1	958.1	937.5	946.3	1014.0	1143.3	936.1	916.7	925.7
Peak	409.0	369.4	355.3	356.5	356.7	409.0	360.0	342.0	342.0	341.9
Utilization										
Total	66%	71%	62%	61%	61%	68%	72%	63%	62%	62%
Base	59%	68%	56%	55%	56%	61%	68%	57%	56%	57%
Peak	94%	85%	84%	84%	84%	97%	86%	84%	84%	84%
Emissions										
GHG eq (mt)	423.3	434.0	449.4	422.9	429.8	455.2	447.4	465.0	438.0	448.1
Acid (10 kt)	102.3	107.6	113.8	106.6	108.9	110.9	111.4	119.1	111.9	115.0
Pm10 (10 kt)	275.0	290.0	299.1	278.5	284.0	293.6	294.4	311.3	290.5	299.5
Payoffs										
Total	17,022	13,358	19,292	20,208	19,674	16,066	13,573	19,731	20,676	20,151
RWE	1,078	1,200	2,106	1,892	1,850	997	1,347	2,148	1,948	1,905

Note: The average EU8 prices are the domestic market prices weighted by the share of domestic supply in total EU8 supply. For RWE in the STACK scenario with lower transmission losses, ξ_{base} = 0.414 and ξ_{peak} = 0 (lower bound) and with higher transmission losses, ξ_{base} = 0.443 and ξ_{peak} = 0.771.

6.2 Alternative division of peak and base load periods (PEAKBASE)

The division of peak load and base load demand is rather arbitrary. Therefore, we evaluate the EMELIE model with respect to the assumption imposed on the share of capacity used in peak load periods, and on the share of the peak load price in the average price. In contrast with the division as presented in Section 2.1, we first assume that peak load demand in a region requires 80% (instead of 90%) of total available capacity. Secondly, we return to the initial model, and we impose the assumption that the peak price is 80% (instead of 90%) of the average price. Finally, we run the model in which both assumptions are imposed simultaneously.

The first assumption lowers the level of the peak demand, and this will have a downward effect on the electricity prices in peak load periods. The second assumption lowers the level of base load price levels, so that the peak load price will increase due to the definition in Section 2. If we impose both restrictions, the effect on the electricity market is ambiguous.

If the ratio peak demand over maximum production capacity is reduced from 90% to 80%, the REF scenario shows lower peak demand (409.0 TWH initially, see Table 5.2, and now 363.5 TWh) at higher prices (€25.64 initially and now €26.54). This is due to the calculation rules in Section 2.2, as peak demand declines, while the share of the peak price in the average price remains unchanged. However, under different scenarios of producer behaviour in a liberalised market, the electricity prices in peak load periods decline due to the lower level of peak demand. On the other hand, prices in base load demand slightly increase for the COMP, STACK, STRA and CROSS scenarios, while the level of base demand increase as well. As a result, the average electricity prices under the COMP and STACK scenario decrease, while they decrease in the STRA and the CROSS scenarios. Total electricity demand increases slightly for all scenarios (except the REF scenario). Obviously, the utilisation of production capacity in the peak load period is lower.

Table 6.2 EU 8 electricity market under different peak-base load assumptions for five scenarios.

	Peak demand is 80% of maximum capacity					*Peak price is 80% of average price*				
Region	REF	COMP	STACK	STRA	CROSS	REF	COMP	STACK	STRA	CROSS
Price										
Average	20.62	16.81	23.82	24.66	24.15	20.62	17.63	25.04	26.11	25.76
Base	18.60	13.95	22.29	23.38	22.74	16.53	12.60	21.04	22.35	21.75
Peak	26.54	26.17	28.26	28.26	28.15	30.77	32.31	35.10	35.40	35.88
Demand										
Total	1423.0	1542.0	1319.3	1300.6	1310.2	1423.0	1517.4	1280.2	1255.8	1259.5
Base	1059.5	1181.0	978.9	960.2	969.1	1014.0	1130.0	916.3	894.4	902.3
Peak	363.5	361.1	340.4	340.4	341.2	409.0	387.4	363.9	361.4	357.2
Utilization										
Total	67%	73%	63%	63%	63%	67%	71%	61%	60%	61%
Base	62%	69%	59%	58%	58%	60%	67%	55%	54%	54%
Peak	85%	85%	82%	82%	82%	96%	91%	87%	87%	86%
Emissions										
GHG eq (mt)	449.3	466.9	474.3	445.3	455.5	442.1	426.1	444.8	416.2	419.7
Acid (10 kt)	111.6	116.1	122.1	113.6	117.4	107.8	104.9	112.6	105.3	106.6
Pm10 (10 kt)	301.2	307.7	320.0	295.7	305.9	287.1	278.2	299.3	279.3	278.4
Payoffs										
Total	17,597	13,068	19,420	20,327	19,775	16,551	13,903	20,293	21,436	21,061
RWE	1,371	1,108	2,120	1,929	1,890	996	1,222	2,179	1,978	1,967

Note: The average EU8 prices are the domestic market prices weighted by the share of domestic supply in total EU8 supply. For RWE in the STACK scenario if peak demand is 80% of maximum capacity $\xi_{base} = 0.467$ and $\xi_{peak} = 1.000$ (upper bound). If the peak price accounts for 80% of the average price, $\xi_{base} = 0.317$ and $\xi_{peak} = 0.125$.

If the peak load price accounts for 80% of the average price instead of 90%, the demand in the REF scenario remains unchanged at 409.0 TWH, while the base load price of electricity decreases from €18.60 in the initial model to €16.53 and the peak load price increases from €25.64 to €32.56. The base load prices in the other scenarios hardly change despite the lower base load price in the REF scenario. The higher peak load price in the REF scenario is observed in the other scenarios as well. The peak load demands in all scenarios are higher as well.

Consequently, the peak load demand in the REF scenario decreases by 10% in comparison with the initial calibration. From the table, we see a similar development of higher peak load prices and lower levels of peak load demand for all other scenarios.

Unlike the initial calibration, the peak load prices in Belgium exceed the base load prices for all five scenarios in this alternative.

Finally, we combine both alternative assumptions discussed above. In this third alternative, the ratio peak demand over maximum production capacity is reduced from 90% to 80%, and the peak load price accounts for 80% of the average price instead of 90%. Table 6.3 shows the results. In the REF scenario, the ratio of base and peak load prices is as under the first alternative, and the ratio of base and peak load demand is as under the second alternative.

Table 6.3 EU 8 electricity market under different peak-base load assumptions for five scenarios.

	Peak demand is 80% of maximum capacity and peak price is 80% of average price Absolute values					*Peak demand is 80% of maximum capacity and peak price is 80% of average price Index (initial model)*				
Region	REF	COMP	STACK	STRA	CROSS	REF	COMP	STACK	STRA	CROSS
Price										
Average	20.62	17.57	24.87	25.73	25.20	100.0	102.5	102.7	102.6	102.6
Base	16.53	13.41	21.76	22.88	22.20	88.9	100.2	100.0	99.9	99.8
Peak	32.56	30.24	33.20	33.20	33.18	127.0	104.2	107.4	107.7	107.9
Demand										
Total	1423.0	1527.5	1296.5	1277.5	1287.1	100.0	100.5	100.1	100.1	100.1
Base	1059.5	1149.4	944.4	925.4	935.1	104.5	99.6	99.8	99.9	99.9
Peak	363.5	378.1	352.2	352.1	352.0	88.9	103.5	101.1	100.8	100.7
Utilization										
Total	67%	72%	62%	61%	62%	100.0	100.5	100.2	100.1	100.1
Base	62%	68%	57%	56%	56%	104.3	99.6	99.8	99.9	99.9
Peak	85%	89%	85%	85%	85%	89.1	103.4	101.1	100.8	100.7
Emissions										
GHG eq (mt)	449.3	445.3	454.5	431.1	438.8	101.6	101.2	99.7	100.9	100.4
Acid (10 kt)	111.6	110.5	115.1	109.0	111.8	103.5	101.3	99.6	101.4	100.9
pm10 (10 kt)	301.2	295.1	301.5	284.3	290.5	104.9	100.9	99.4	101.6	100.5
Payoffs										
Total	17,597	13,993	20,379	21,285	20,727	106.3	103.6	104.2	104.1	104.1
RWE	1,297	1,220	2,216	2,002	1,963	131.0	100.1	104.0	104.4	104.6

Note: The average EU8 prices are the domestic market prices weighted by the share of domestic supply in total EU8 supply. For RWE in the STACK scenario, ξ_{base} =0.428 and ξ_{peak} = 0.467.

Due to this alternative division rules between peak and base, the level of prices increased ranging from 2.1% in the STRA scenario to 2.7% in the COMP scenario. At the same time, the total demand increased as well by 0.5% for all scenarios (except the REF scenario). Peak load prices are substantially higher ranging from 4–6% across scenarios, while peak demand increased by 2–3%. For the base load prices and demand levels, only minor changes were observed.

6.3 Uniform prices (UNIFORM)

The liberalisation of the electricity market resolves the market access barriers. Ultimately, if there would be no physical restriction left, we expect the electricity market of the EU8 to clear at one unique price. However, there are still physical constraints due to transmission capacity and production capacity. Impacts of these barriers can be assessed by calibration of the EMELIE model with a uniform reference price. Table 6.4 shows that in the REF scenario, the average price is equal for all countries. The differences in the peak load prices are due to the assumptions on the peak load price as discussed in Chapter 5.

In the COMP scenario, the average price declines by 2.7% and the demand increases by 3.4% compared to the initial calibration. In the scenarios with strategic behaviour of electricity producers, a uniform initial prices leads to higher average electricity prices. Despite these higher prices, the demand level increases as well for the scenarios STACK, STRA and CROSS.

Table 6.4 Electricity prices and electricity supply during different load periods for five scenarios assuming uniform initial prices.

	Absolute values					*Index (initial model)*				
	REF	COMP	STACK	STRA	CROSS	REF	COMP	STACK	STRA	CROSS
Price										
Average	20.62	16.55	25.23	25.98	25.36	100.0	96.6	104.2	103.6	103.3
Base	18.56	12.68	22.96	23.96	23.13	99.8	94.8	105.6	104.6	104.0
Peak	25.73	29.09	31.35	31.35	31.34	100.4	100.2	101.4	101.7	101.9
Demand										
Total	1423.0	1554.8	1283.7	1267.3	1275.6	100.0	102.3	99.2	99.3	99.2
Base	1014.0	1188.2	936.6	920.2	928.5	100.0	103.0	99.0	99.3	99.2
Peak	409.0	366.6	347.0	347.0	347.1	100.0	100.3	99.6	99.4	99.3
Utilization										
Total	67%	73%	61%	61%	61%	99.7	102.0	98.7	98.9	98.8
Base	59%	70%	56%	55%	55%	99.5	102.6	98.5	98.8	98.7
Peak	96%	86%	83%	83%	83%	100.0	100.1	99.3	99.1	99.1
Emissions										
GHG eq (mt)	471.3	461.9	442.7	425.6	429.9	106.6	105.0	97.1	99.6	98.3
Acid (10 kt)	118.2	115.2	114.8	110.8	111.8	109.6	105.6	99.3	103.1	100.9
Pm10 (10 kt)	322.5	309.0	299.7	288.2	290.9	112.3	105.7	98.8	103.0	100.6
Payoffs										
Total	16,081	12,414	20,743	21,523	20,829	97.2	91.9	106.1	105.2	104.7
RWE	1,000	1,168	2,045	1,870	1,823	101.0	95.7	96.0	97.5	97.2

Note: The average EU8 prices are the domestic market prices weighted by the share of domestic supply in total EU8 supply. For RWE in the STACK scenario: A: $\xi_{base} = 0.075$ and $\xi_{peak} = 0.130$.

Although not shown in the table, even in the COMP scenario there are already differences in electricity prices across different national markets. Especially, the prices of electricity in France, Norway and Finland, i.e. the countries with cheap production technologies such as nuclear power and hydropower, are low. Net importers or countries relying on more expensive technologies show higher electricity prices.

As Table 6.4 shows, we observe a similar pattern for the base load period. In the peak load period, electricity prices are at a substantially higher level, and the prices are not uniform over countries although there is limited variation in electricity prices across national electricity markets. In base load period, the average electricity price of the EU8 declines for the COMP scenario in comparison with the REF scenario, while in the peak load period we observe the reverse case.

The example of the uniform initial prices clearly shows the complexity of interactions at play in a liberalised electricity market. Even if we take a uniform electricity price as a starting point, the combination of restrictions on electricity capacity and trade, and strategic behaviour causes price differences on national markets. Note, however, that the variation in prices decreases if we start with a uniform price.

6.4 Price elasticities of demand

In our initial EMELIE model, we use a base load elasticity of –0.4 and we assume that the peak load elasticity is twice the base load elasticity (i.e. –0.8). We verify our price elasticities in two dimensions. First, we evaluate the ratio of price elasticities between peak period and base period. We assume a more elastic peak period demand, but we assess the model when the base period and peak period elasticities are equal. We then maintain possible geographical differences in price elasticities. Note that we ignore the case that price elasticities for peak load demand are smaller than those for base load demand, simply because it seems unrealistic. Secondly, we evaluate the level of the elasticities given the more elastic demand for electricity in the peak period. We rerun the EMELIE model by decreasing and increasing the level of price elasticities by 25%. The different sets of alternative elasticities are summarized in Table 6.5.

Table 6.5 Price elasticities of the demand for electricity per load periods.

	Ratio of peak and base load elasticities	
Level of elasticities	Peak = base	Peak > base
Low		–0.6; –0.3
Medium	–0.4; –0.4	–0.8; –0.4
High		–1.0; –0.5

Note: For Denmark and the Netherlands the base load elasticities are –0.295 and –0.29 respectively.

In the EMELIE model we assume that electricity demand is represented by a simple CES demand function, which depends on three parameters, reference demand, reference price, and the price elasticity. Note that we distinguish different demand functions per country and per load period. First, we evaluate similar price elasticities for peak and base load demand, and then we evaluate price elasticities by varying the level of elasticities.

6.4.1 Similar price elasticities for peak and base load demand (ELASEQ)

Table 6.6 presents the results of the EMELIE model in the case that the price elasticities of the peak load periods are equal to those of the base load periods. In fact, we assume that the peak demand elasticity is less elastic than in the initial case. From Table 6.6, we can see that there are only minor changes in the prices and demands in the base load periods. For all scenarios, the electricity price in the peak load period increases. In the COMP scenario, the price increases by 1.5%, while in the STACK, STRA and CROSS scenarios the prices increase by approximately 10%. The demand in these scenarios decreases by less than 1%, while the amount of emissions slightly increases. The payoffs increase by 13–14% in these scenarios.

In the peak load period, we observe substantially higher levels of electricity prices when electricity producers act strategically (STRA, STACK or CROSS scenario). The average peak load price in the EU8 increases by approximately 30%, while the total demand for electricity during peak load period only declines by roughly 4% in the scenarios STRA, STACK and CROSS.

Although it is not shown in the Table 6.6, there are many forces at play at the national and international level of the electricity market, if we assume similar price elasticities of demand in base and peak load period. These dynamics largely depend on the circumstances. We conclude that less elastic demands opens opportunities for electricity producers to act strategically.

Table 6.6 EU8 electricity market when price elasticities of peak and base load demand are similar for five scenarios assuming.

	Absolute values					*Index (initial model)*				
	REF	COMP	STACK	STRA	CROSS	REF	COMP	STACK	STRA	CROSS
Price										
Average	20.62	17.49	26.88	27.82	27.19	100.0	102.0	111.0	111.0	110.8
Base	18.60	13.38	21.74	22.91	22.24	100.0	100.0	100.0	100.0	100.0
Peak	25.64	30.02	41.30	41.34	40.94	100.0	103.4	133.6	134.1	133.1
Demand										
Total	1423.0	1532.4	1282.9	1263.2	1273.1	100.0	100.9	99.1	99.0	99.0
Base	1014.0	1153.8	946.2	926.6	936.0	100.0	100.0	100.0	100.0	100.0
Peak	409.0	378.5	336.6	336.6	337.2	100.0	103.6	96.6	96.4	96.5
Utilization										
Total	67%	72%	62%	61%	61%	100.0	100.8	99.1	99.1	99.1
Base	60%	68%	57%	56%	56%	100.0	100.0	100.0	100.0	100.0
Peak	96%	89%	81%	81%	81%	100.0	103.5	96.8	96.6	96.7
Emissions										
GHG eq (mt)	442.1	443.5	461.1	432.9	444.8	100.0	100.8	101.1	101.3	101.7
Acid (10 kt)	107.8	109.1	117.3	109.5	113.9	100.0	100.0	101.5	101.9	102.8
Pm10 (10 kt)	287.1	291.0	311.4	288.9	300.9	100.0	99.5	102.7	103.3	104.1
Payoffs										
Total	16,551	13,887	22,458	23,403	22,754	100.0	102.8	114.8	114.4	114.3
RWE	990	1,215	2,494	2,256	2,247	100.0	99.6	117.0	117.6	119.8

Note: The average EU8 prices are the domestic market prices weighted by the share of domestic supply in total EU8 supply. For RWE in the STACK scenario: ξ_{base} =0.429 and ξ_{peak} = 0.507.

6.4.2 Varying the level of elasticities of demand (ELASTIC)

We return to our original calibration of the EMELIE model in which the ratio of price elasticity of peak load demand versus base load demand as in the initial model is restored. Now, we vary the level of price elasticities of electricity demand. First, we assume a less elastic electricity demand, and then we assume a more elastic electricity demand. In both cases, we alter the level of price elasticities by 25%.

On average, the electricity price slightly declines with the absolute value of the price elasticity of demand in the COMP scenario. In the scenarios with strategic behaviour of electricity producers, it is the other way around. In STACK, STRA and CROSS, the level of the electricity prices decrease with the absolute level of the price elasticity for electricity. Subsequently, the level of demands decline as the price level rises. However, Table 6.7 shows that firms can realise much higher payoffs whenever the demands for electricity are rather price inelastic. The higher prices overcompensate the reduction in demand. In the case of less elastic electricity demand, electricity producers can exercise more market power altogether.

Table 6.7 EU 8 electricity market when electricity demand is less or more elastic for five scenarios.

	Less price elastic demand					*More price elastic demand*				
	REF	COMP	STACK	STRA	CROSS	REF	COMP	STACK	STRA	CROSS
Price										
Average	20.62	16.77	28.25	29.14	28.05	20.62	17.44	22.16	23.06	22.88
Base	18.60	12.69	26.58	27.78	26.30	18.60	13.95	19.33	20.54	20.26
Peak	25.64	29.29	32.61	32.62	32.60	25.64	28.53	30.28	29.99	30.18
Demand										
Total	1423.0	1509.9	1262.7	1250.4	1260.3	1423.0	1525.3	1328.8	1302.7	1306.1
Base	1014.0	1138.3	912.9	900.7	910.8	1014.0	1161.0	984.5	955.1	960.9
Peak	409.0	371.6	349.7	349.7	349.5	409.0	364.4	344.3	347.6	345.2
Utilization										
Total	67%	71%	61%	60%	61%	67%	72%	64%	63%	63%
Base	60%	67%	55%	54%	55%	60%	68%	59%	57%	58%
Peak	96%	87%	84%	84%	84%	96%	86%	83%	83%	83%
Emissions										
GHG eq (mt)	442.1	438.8	463.4	433.2	442.4	442.1	445.6	441.6	414.2	419.3
Acid (10 kt)	107.8	108.3	121.6	112.5	115.3	107.8	110.4	111.3	104.4	106.4
Pm10 (10 kt)	287.1	289.0	312.3	282.3	290.1	287.1	294.4	292.2	275.7	279.7
Payoffs										
Total	16,551	12,757	23,846	24,591	23,386	16,551	13,924	17,632	18,583	18,425
RWE	990	1,196	2,790	2,268	2,259	990	1,192	1,765	1,628	1,598

Note: The average EU8 prices are the domestic market prices weighted by the share of domestic supply in total EU8 supply. For RWE in the STACK scenario if the demand is less price elastic: $\xi_{base} = 0.435$ and $\xi_{peak} = 0.250$, and more elastic: $\xi_{base} = 0$ (lower limit) and $\xi_{peak} = 0.056$.

Moreover, the developments observed for the whole EU8 electricity market when varying the levels of price elasticity also hold for the separate markets in peak and base load periods. Again, although not shown in the table, the underlying results of firms an national electricity markets indicate that there are a lot of dynamics (exports and imports) going on national markets a well as on the international market.

6.5 Transmission capacity (TRANSM)

In the initial calibration of the EMELIE model, there are transmission capacities between countries are included. In the formation of one large European electricity market, these transmission capacities can be restrictive. In order to evaluate their role in the results of the EMELIE model, we rerun the EMELIE model for two extreme cases. First, we reduce the possibility of trading by minimizing the transmission capacity to zero. All individual EU8 countries have to supply their own domestic demand for electricity. The electricity price is therefore largely driven by the available production technologies in a country. We expect large differences in prices across countries. Secondly, we assume that there are no transmission restrictions anymore. Neighbouring countries have large opportunities to trade. We expect that the price differences between countries of most scenarios will be much smaller due tot the increased possibilities to compete, particularly for the full competition scenario (COMP).

Table 6.8 EU8 electricity market with reduced and full transmission capacity for five scenarios.

	Reduced transmission					*Full transmission*				
	REF	COMP	STACK	STRA	CROSS	REF	COMP	STACK	STRA	CROSS
Price										
Average	20.62	16.55	25.23	25.98	25.36	20.62	18.25	22.94	23.99	23.82
Base	18.60	12.68	22.96	23.96	23.13	18.60	14.66	20.01	21.36	21.15
Peak	25.64	29.09	31.35	31.35	31.34	25.64	28.99	31.18	31.21	31.19
Demand										
Total	1423.0	1554.8	1283.7	1267.3	1275.6	1423.0	1454.1	1313.9	1290.8	1293.7
Base	1014.0	1188.2	936.6	920.2	928.5	1014.0	1090.3	969.8	946.6	949.5
Peak	409.0	366.6	347.0	347.0	347.1	409.0	363.8	344.1	344.2	344.2
Utilization										
Total	67%	73%	61%	61%	61%	67%	69%	63%	62%	62%
Base	59%	70%	56%	55%	55%	60%	65%	59%	57%	57%
Peak	96%	86%	83%	83%	83%	96%	86%	83%	83%	83%
Emissions										
GHG eq (mt)	471.27	461.9	446.4	425.6	428.5	330.2	383.4	472.3	435.9	441.6
Acid (10 kt)	118.2	115.2	116.4	110.8	111.2	78.3	91.6	123.2	112.8	115.0
Pm10 (10 kt)	322.5	309.0	304.2	288.2	289.1	215.9	255.4	323.9	294.6	302.4
Payoffs										
Total	16,081	12,414	20,743	21,523	20,829	17,473	15,043	18,233	19,378	19,207
RWE	1,000	1,168	2,045	1,870	1,823	1,029	1,091	1,757	1,562	1,530

Note: The average EU8 prices are the domestic market prices weighted by the share of domestic supply in total EU8 supply. For RWE in the STACK scenario with reduced transmission is $\xi_{base} = 0.470$ and $\xi_{peak} = 1.000$ (upper bound), and under full transmission is $\xi_{base} = 0.329$ and $\xi_{peak} = 0.134$.

Table 6.8 presents the results of the EU8 electricity market when there are reduced and full transmission capacities between neighbouring countries. In the COMP scenario, the electricity price declines in the case of reduced transmission and increases in the case of full transmission, which is rather counterintuitive.

However, the EU8 market has a number of countries like France, Norway and Sweden which have sufficient production capacities of cheap technologies. Since transmission is reduced, there are less incentives to export electricity to countries with high electricity prices. So the electricity prices in these countries remain low, and they account for a substantial part of the average EU8 price. In the case of full competition, this reasoning can be reversed.

Furthermore, Table 6.8 shows that more trade opportunities imply lower prices in an electricity market with strategically acting electricity producers. Although more electricity is demanded under the full transmission market alternative compared to reduced transmission market alternative, the higher demands do not compensate for the lower electricity prices. In a reduced transmission market, the total amounts of payoffs are substantially higher. In that case, exercising market power pays off.

6.6 Environmental constraints (ENVIRON)

To study the effect of environmental constraints on the model, we define emission restrictions as a fraction of the level of emissions in the reference situation, where the market is being served by minimising the cost of production. While we assume that there are no restrictions in the model for acidifying emissions and fine particles (PM10), we do study restrictions on greenhouse gas.

In the first scenario on the emissions, we assume that the level of greenhouse gas emissions with respect to the level in the reference case (representative for the year 2000) has to be reduced with 10%. While the Kyoto target translates into a reduction of 2.3% with respect to the level of emissions in 2000 in the eight studied countries, it is reasonable to assume that the electricity sector contributes more, as there is a large potential to do so at a relatively low cost. In that sense, the 10% reduction target makes sense.

Alternatively, it is also possible to run the EMELIE model with a simplified tradable permit system in place. In the second scenario, the implied level of greenhouse gas emission reductions is calculated with a permit price of €5 per tonne carbon equivalent. Then the shadow price κ_{ghg} is no longer a variable, but fixed at €5 per tonne carbon equivalent. The emission constraint in equation (3.8) is no longer part of the model, but the induced level of reduction can be derived ex post after the model run.

Table 6.9 shows the summary results of the two environmental restrictive scenarios. RWE has a good scope to increase its profits in the 10% reduction scenario, while the potential increase in profits is very low in the permit price scenario. A possible explanation for this difference may be that RWE has still cheap alternative technologies available to increase its supply to the market in the 10% reduction scenario, while the permit price increases the cost of dirty technologies leading to a near dissipation of the payoff increase.

Table 6.9 Electricity prices and electricity supply during two types of emission constraints.

	10% GHG reduction					*Fixed permit price 5€/ tonne GHG equiv.*				
	REF	COMP	STACK	STRA	CROSS	REF	COMP	STACK	STRA	CROSS
Price										
Average	20.62	18.00	26.42	26.17	25.87	20.62	18.82	26.56	28.25	26.35
Base	18.60	14.35	24.38	24.32	23.89	18.60	15.35	24.57	26.86	24.41
Peak	25.64	29.30	31.83	30.98	31.06	25.64	29.34	31.83	31.83	31.44
Demand										
Total	1423.0	1487.3	1245.6	1253.2	1256.8	1423.0	1462.0	1242.7	1212.4	1245.6
Base	1014.0	1124.4	905.0	905.3	910.0	1014.0	1099.6	902.1	871.8	902.2
Peak	409.0	362.8	340.6	347.9	346.8	409.0	362.4	340.5	340.5	343.4
Utilization										
Total	67%	70%	60%	60%	60%	67%	69%	60%	58%	60%
Base	60%	66%	54%	54%	55%	60%	65%	54%	52%	54%
Peak	96%	85%	82%	84%	83%	96%	85%	82%	82%	83%
Emissions										
GHG eq (mt)	442.1	397.9	397.9	397.9	397.9	442.1	365.9	394.8	346.3	400.8
permit price	0.00	2.16	4.62	1.77	2.16	0.00	5.00	5.00	5.00	5.00
Reduction	0%	10%	10%	10%	10%	0%	17%	11%	22%	9%
Acid (10 kt)	107.8	97.5	99.7	98.7	99.0	107.8	88.5	99.0	85.5	101.7
Pm10 (10 kt)	287.1	261.1	261.6	254.7	256.3	287.1	235.7	259.8	214.0	266.9
Payoffs										
Total	16,551	14,732	21,978	21,627	21,325	16,551	18,131	23,236	24,692	24,052
RWE	990	1,476	2,651	2,005	1,995	990	2,082	2,530	2,518	2,485

Note: The average EU8 prices are the domestic market prices weighted by the share of domestic supply in total EU8 supply. For RWE in the STACK scenario: $\xi_{base} = \xi_{peak} = 0$ in the 10% reduction scenario, while $\xi_{base} = 0$ and $\xi_{peak} = 1$ in the €5 permit price scenario.

6.7 Comparison

We have carried out a sensitivity analysis in order to evaluate whether or not our findings with the initial EMELIE model calibration are robust. Generally, we can argue that the model results are quite robust, although it is also clear from the sensitivity analysis that the results are not always straightforward. In particular, the EMELIE model is rather complex, and it includes many aspects of a liberalised electricity market, while consequences of environmental policies can also be studied. For instance, national electricity markets will clear at different market price simulations even if the market would start off with uniform reference prices. Clearly, differences in and restrictions on production capacity, transmission capacity and environmental objectives contribute to different market clearing prices. When maximizing profits and acting strategically, electricity producers face different restrictions (environment, production capacity or transmission capacity) in different circumstances.

The impact of transmission losses is rather straightforward. Higher transmission losses will increase the level of prices and reduce demand for electricity. The opposite development holds for lower transmission losses. Table 6.10 summarises the scenarios.

Table 6.10 Summary of scenarios.

Scenario	Description	Market price of electricity (€ per MWh)					
		ξ-base	ξ-peak	COMP	STACK	STRA	CROSS
BAU	Business as usual	0.439	0.000	17.14	24.22	25.07	24.55
LAMBDA	Transmission losses +25%	0.443	0.771	17.47	24.83	25.73	25.22
	Transmission losses –25%	0.414	0.000	16.75	23.55	24.41	23.92
PEAKBASE	Peak demand 80% production capacity	0.467	1.000	16.81	23.82	24.66	24.15
	Base price 80% average price	0.317	0.125	17.63	25.04	26.11	25.76
	Both effects	0.428	0.467	17.57	24.87	25.73	25.20
UNIFORM	Uniform regional reference prices	0.075	0.130	16.55	25.23	25.98	25.36
ELASEQ	Equal elasticity in both load periods	0.429	0.507	17.49	26.88	27.82	27.19
ELASTIC	Elasticity +25%	0.000	0.056	17.44	22.16	23.06	22.88
	Elasticity –25%	0.435	0.250	16.77	28.25	29.14	28.05
TRANSM	Reduced level of electricity transmission	0.470	1.000	16.55	25.23	25.98	25.36
	Unrestricted electricity transmission	0.329	0.134	18.25	22.94	23.99	23.82
ENVIRON	GHG emissions –10%	0.000	0.000	18.00	26.42	26.17	25.87
	Permit price €5 per tonne GHG equiv.	0.000	1.000	18.82	26.56	28.25	26.35
	Average	0.303	0.389	17.37	25.00	25.86	25.26
	Variance	0.037	0.159	0.45	2.70	2.77	1.89

Table 6.10 shows the effect of the sensitivity analysis on the market power mark-ups and the prices in four behavioural scenarios. The market power mark-up in base load is 0.3 with a relatively low variance, while the market power mark-up in the peak load is almost 0.4 with a relatively high variance. The variance in the price is also higher in the imperfect market behavioural scenarios (STACK, STRA, CROSS), but highest in the STRA scenario.

The effect of the scenarios on the prices is quite varied. An increase in transmission losses leads to a moderate price increase in perfect and imperfect competition.

While the price increase is in the same direction after lowering the reference price of base load, the price increase is relatively higher under imperfect competition. Uniform prices, however, decrease the prices under perfect competition, while it increases antagonistically the prices under imperfect competition. The elasticity is clearly the most sensitive parameter of the model. Small variations in the elasticity can have large impacts on the resulting market prices. Lowering the elasticity of peak demand to the level of elasticity of base demand leads to a mild price increase under perfect competition, due to the change in the demand curve, but a much higher price increase under imperfect competition. In addition, a uniform price decrease lowers the prices under perfect competition, but increases the price under imperfect competition. Finally, the addition of environmental constraints leads to a substantial increase in production cost in both perfect and imperfect competition.

7. Conclusions

The main research question in this report was is the following: What will happen to the wholesale price of electricity, the demand for electricity, the profits of firms, and finally the different kind of emissions under different types of producer behaviour? To answer this question this report started with a general discussion of the European electricity market, which is in the middle of a transformation process from a monopolistic state regulated market to a liberalised market where firms can compete with each other on various national markets and internationally.

To study this complex change process, Chapter 2 presented and discussed data on the specific situation in the electricity market of eight European countries, namely Belgium, Denmark, Finland, France, Germany, The Netherlands, Norway, and Sweden. This data comprised the calibration of constant elasticity of substitution (consumer) demand curves for base and peak load periods of electricity, where peak load represents the 20% of hours with the highest hourly supply per year. In addition, data is presented on the transmission capacity among countries, while transmission within a country is assumed to be unlimited. Transmission losses between production and delivery of electricity among and within countries are also presented. There are at most 12 different technologies per country. At this level we presented installed capacity, variable costs, and emission factors of three pollutants, namely greenhouse gas, acidifying and fine particles emissions. Finally, the data on cross-border ownership relations among firms is presented as well.

Chapter 3 presents and discusses the structure of the static EMELIE model and this shows how trade, capacity and environmental constraints are included into the model. Firm behaviour depends on the ability of firms to exercise market power, which again depends upon the market share, the elasticity of demand. A large firm has a large market share and a higher ability to increase prices by strategically choosing production. Passive cross-border ownership relations change the levels of market power among firms in the eight considered European markets. Chapter 4 summarizes the five scenarios of market structure.

The base results with the model are presented in Chapter 5. This chapter discusses in length the type of results, which can be obtained with the model. The results consist of wholesale prices, firm’s payoffs, emissions and the use of technologies. In addition, wholesale prices are decomposed into the contribution of production, capacity usage and trade. It turns out that 2/3rd of the price is needed to cover production costs, while 1/3rd is needed to keep the capacity up and running. Only 3% of the price is needed for trade. In the case of imperfect competition the price of electricity is increased with the market power mark-up, which is a cap or profit margin on top of the marginal production costs, capacity payments and trade prices.

The consequences of liberalisation for the environment are ambiguous. The exercise of market power can be beneficial for the environment. In the case where there are strategically acting firms (STRA), all environmental themes show a decline compared to the reference scenario. If RWE acts like a price fighter (STACK), the environment is worse off compared to the reference scenario. This is probably due to the rather dirty technologies that RWE owns. In the case of full competition, greenhouse gases would decline, but acidification and smog formation would increase.

To study the robustness of the model, a number of sensitivity analyses have been undertaken with the model in Chapter 5. The overall effects were largely in the expected direction showing that the model is quite robust against perturbations. The details at the country level could, however, deviate from the overall pattern, showing that due to geographical differences, differences in production technologies and market structures, some country or countries do not follow the general trend. The elasticity as already discussed at various places in this report turns out to be the most sensitive parameter of the model. For instance, a low elasticity pushes down the maximum allowable market share to the elasticity value.

In a liberalised market, large firms are most likely to behave strategically in order to make sufficient profits, creating an imperfect market. There are incentives for a single firm to become a market leader and to make a first move by setting its levels of production. In case the followers do not change their reactions, they will reduce their supply in that market after obtaining information on this level of production. In that case there is a welfare transfer between the leader and the followers. The joined total payoff can increase or decrease.

Future simulations with the EMELIE model will consider various merger and demerger scenarios. It is for instance not a priori clear whether a merger will increase the joint profit of the merged firm, especially when there are many large firms in the market. Another interesting issue would be to simulate various leader-follower scenarios, next to our presumed leadership of RWE (Germany), so that we can study the potential changes in the market of this scenario.

Two more extensions of the model are envisaged. Firstly, the EMELIE model will become a dynamic model, so that long-term consequences of investment decisions on the liberalised electricity market can be assessed. It is particularly interesting to study the investment choices and price development over time with and without regulation for a number of future demand profiles. Secondly, instead of including a passive type of cross-owners, it would be interesting to study active cross-border ownership relations. Then, firms own production capacity in different countries, and they can allocate their production across these countries. Then, control over interconnection capacity can generate a new source of market power. In a process of market integration of the European electricity market, this active ownership issue is much more realistic than the passive ownership.

These are all promising fields for future research towards which we intend to use the EMELIE model. The current report has shown that the EMELIE model is a useful tool for policy analysis as the model is quite robust to perturbations.

References

Amundsen, E. & Bergman, L. (2002). Will cross-ownership re-establish market power in the Nordic power market? *The Energy Journal, 23*(2): 73-95.

Bigano, A. & Proost, S. (2003). *The opening of the European electricity market and environmental policy: does the degree of competition matter?* Katholieke Universiteit Leuven. Energy, Transport and Environment, EEE working paper series no.13. Paper available from: http://www.ictp.trieste.it/~eee/files/WP13_Bigano.pdf

Energieraad. (2004). *Behoedzaam stroomopwaarts, beleidsopties voor de Nederlandse electriciteitmarkt in Europees perspectief.* Van Deventer, Den Haag, 108 pp.

Heinzow, T. (2004). *Emission factors for CO_2, SO_2, NO_x, CH_4, N_2O and PM10*. Personal communication.

Kemfert, C. (1999). *Liberalisation of the German electricity market - strategies and opportunities.* Nota di Lavoro, Milan, Italy. 95/1999.

Kemfert, C. & Tol, R. S. J. (2000). *The liberalisation of the German electricity market - modelling an oligopolisitic structure by a computational game theoretic model.* Working paper, Oldenburg, Germany. 89/2000.

Kemfert, C., Lise, W. & Oestling, R. (2004). The European electricity market: Does liberalisation bring cheaper and greener electricity? Oldenburg University, Oldenburg. Paper available from: http://www.uni-oldenburg.de/speed/xdocs/pdf/EMELIEEurope.pdf

Knops, H.P.A. (2003). *Securing electricity supply: what is the potential of national measures in the European market*. International Institute of Energy Law, Leiden University, the Netherlands. Available from: http://www.electricitymarkets.info/symp03/doc/b1_4-paper.pdf.

Lise, W., Kemfert, C. & Tol, R. S. J. (2003). *The German electricity market - does liberalisation bring competition?* Nota di Lavoro, Milan, Italy. 3.03.

Lise, W., Linderhof, V. & Kuik, O. (2003). *Liberalising the Dutch electricity market: Are there environmental impacts?* Paper available from: http://www.electricitymarkets.info/symp03/doc/a1_1-paper.pdf

Madlener, R., Kumbaroglu, G., & Ediger, V. S. (2003). *Technology adoption modelling in situations of irreversible investments under uncertainty: the case of the Turkish electricity supply industry*. Paper prepared for the international conference on policy modeling (EcoMod 2003), 3-5 July, Istanbul, Turkey. Paper available from: http://www.ecomod.net/conferences/ecomod2003/ecomod2003_papers/Madlener.pdf

Pineau, P.O. & Murto, P. (2003). An oligopolistic investment model of the Finnish electricity market. *Annals of Operations Research, 121,* 123–148.

Schils, J. (2003). Eurelectric: Vele miljarden nodig voor Europese energiemarkt. *Energie Nederland, 6*(14), 6.

Tirole, J. (1988). *The Theory of Industrial Organisation*, MIT Press, Cambridge, Massachusetts.

Van der Woerd, F. & Lise, W. (2004). *Emergent strategies of electricity producers: Perspectives from a small country.* IVM report (W-04/12), Institute for Environmental Studies, Vrije Universiteit, Amsterdam.